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In The

Supreme Court of the United States

October Term, 1972

No. 72-67

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Petitioner,

v.

FEDERAL POWER COMMISSION,
Respondent.

No. 72-68

PUBLIC SERVICE COMMISSION OF NEW YORK,
Petitioner,

v.

FEDERAL POWER COMMISSION,
Respondent.

No. 72-69

MUNICIPAL DISTRIBUTORS GROUP,
Petitioner,

v.

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On Writs of Certiorari to the United States Court of Appeals for the Fifth Circuit

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Petitions for Certiorari filed September 5, 1972 (No. 72-67) and October 20, 1972 (Nos. 72-68, 72-69); Certiorari Granted January 15, 1973

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IN THE

United States Court of Appeals

FOR THE FIFTH CIRCUIT

No. 71-2761

On Petitions to Review Orders of the Federal Power Commission

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JOINT APPENDIX

(PART II)

SOUTHERN LOUISIANA AREA RATE CASE,
PLACID OIL COMPANY, ET AL.,
Petitioners,

v.

FEDERAL POWER COMMISSION,
Respondent.

[886-G]

UNITED DISTRIBUTION COMPANIES

Docket AR 69-1

DIRECT TESTIMONY OF ROBERT H. SARIKAS

Q. Will you please state your name and address?

A. Robert H. Sarikas.

Q. By whom are you employed and in what position?

A. I am Manager of Rates and Rate Research for Illinois Power Company.

Q. Will you please state your formal education?

A. I attended Washington University, and received a BS Degree. My Major field of concentration was electrical engineering. In the course of my undergraduate work and also subsequent to graduation, I have had formal training in the fields of economics, finance, statistics and accounting. I am a registered professional engineer holding a certificate in the State of Illinois.

Q. Are you a member of any professional association?

A. Yes, I am a member of the Institute of Electrical and Electronics Engineers. I am also a member of the National and the Illinois Societies of Professional Engineers, the American Society for Engineering Education, and the Institute of Management Science.

Q. Will you please summarize your professional experience?

A. I have been employed by Illinois Power Company since 1941 and, except for periods of military service during World War II and the Korean Conflict, I have had various assignments in the engineering and rate departments of that Company.

Q. What are your duties in your present position?

A. As Manager of Rates and Rate Research I am responsible for planning, coordinating, and controlling all rate and rate research activities which include the development and recommendation of improvement in

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the Company's rate structure, review of contract provisions, and testimony before regulatory bodies with respect to rate design, cost and value of service and other matters. My duties include, among other things, active participation in economic studies of proposed alternative methods of Company operations and capital additions. Such studies are performed for the purpose of evaluating the proposals and assisting management in the making of appropriate decisions. These studies are normally based upon investment and operating cost data received from various operating and engineering departments affected by the proposals.

Q. Have you had published any papers in the field of engineering and economics?

A. Yes, I am the author of over twenty published technical papers and articles.

Q. Are any of these technical papers in the field of load characteristics and economics?

A. Seven of these publications are in that area. Typical among them are "Distribution System Load Characteristics and Their Use in Planning and Design", published in AIEE Transactions Vol. 76, 1957; "Digital Computer Studies, Load Analysis, and Economic Evaluation Techniques", at Power Distribution Conference, University of Texas, 1962; "Economic Justice and the Cost of Utility Relocation", in Public Utilities Fortnightly, November 10, 1960; "Effect of Demand Interval Upon Indicated Peak Demand", AIEE Technical Paper CP

62-114, 1962; and "Load Characteristics of Standard and Quick Recovers Water Heaters", IEEE Technical Paper CE 30-90, 1963.

Q. On whose behalf are you appearing in this proceeding and for what purpose?

[886-I]

A. I am appearing on behalf of the members of the United Distribution Companies Group which I will refer to as "UDC". I have been asked to compile the responses to a questionnaire circulated to all UDC members and prepare an exhibit showing relevant composited information gleaned from those responses and to draw conclusions from that information.

Q. Have you prepared such an exhibit?

A. I have supervised the preparation of Hearing Exhibit 1 which shows total UDC annual and peak-day natural gas requirements and supply, compound annual growth rates of annual and peak day volumes and miscellaneous data.

Q. Will you generally describe the procedure used for processing the responses you received from the UDC members?

A. I received the questionnaire responses from the UDC members, and supervised the preparation of the composite data shown in Hearing Exhibit 1. The data was summarized manually and, where appropriate, by means of electronic data processing equipment. Before summarizing the data, the individual company responses were reviewed in order to determine appropriate adjustments needed to eliminate duplications caused by intracompany sales and to adjust for disparities in estimates of supply and requirements of members buying from and selling to other members. It was also necessary to

review the data furnished to insure comparability with respect to time periods, volumes, and pressure base. After reviewing the data, I decided that

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certain summaries and analysis relating to requirements, supply deficiency, and growth rates were appropriate. A computer program was designed to aggregate the data from the individual company questionnaires and provide the summary shown in my Exhibit.

Q. Will you please explain how sales between UDC members have been adjusted in compiling the data shown in Hearing Exhibit 1?

A. The requirements estimated by the individual members as Sales for Resale to other UDC members have been excluded from the total annual and peak day requirements of UDC members. Similarly the amount estimated by the individual members as supply from other UDC members has been excluded from the total supply for UDC members. The total additional gas supply needed for all UDC members is the difference between the adjusted total gas requirements and the adjusted total gas supply as I have just described.

Q. Were any other adjustments required?

A. Yes. Numerous small adjustments were necessary. For example, where the responses did not break-down future requirements into separate classes such as residential and commercial, it was necessary to pro-rate the amount between those two classes in proportion to the past experience of the particular utility.

Q. Will you please explain Sheet 1 of Schedule 1 of Hearing Exhibit 1?

A. That sheet provides a listing of estimated additional natural gas supply needed by all UDC members

for both annual and peak day requirements for each year 1970 through 1975 and 1980.

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Q. Will you please explain Sheet 2 of Schedule 1 of Hearing Exhibit 1?

A. That sheet provides for years 1969 through 1975 and 1980 a listing of the estimated annual requirements of UDC by various classes of sales and miscellaneous requirements such as company use and unaccounted for losses which have been sumarized under the classification "Other".

Q. Will you please explain Sheet 3 of Schedule 1 of Hearing Exhibit 1?

A. That sheet provides for years 1969 through 1975 and 1980 a listing of the estimated annual supply for UDC by various sources of supply such as their own production, purchases from independent producers and purchases from pipelines.

Q. Will you please explain Sheet 4 of Schedule 1 of Hearing Exhibit 1?

A. That sheet provides a summary of the estimated peak day requirements of UDC in the same manner as the estimate of annual requirements shown on Sheet 2 of Schedule 1.

Q. Will you please explain Sheet 5 of Schedule 1 of Hearing Exhibit 1?

A. That sheet presents in the same form as Sheet 3 of Schedule 1 the estimated peak day supply for UDC.

Q. Will you please explain Sheet 6 of Schedule 1 of Hearing Exhibit 1?

A. That sheet provides for years 1962 through 1968 a listing of the estimated annual requirements of UDC by various classes of sales and miscellaneous require-

ments such as company use and unaccounted for losses which have been summarized under the classification

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"Other".

Q. Will you please explain Sheet 7 of Schedule 1 of Hearing Exhibit 1?

A. That sheet provides a summary of the estimated peak day requirements of UDC in the same manner as the estimate of annual requirements shown on Sheet 6 of Schedule 1.

Q. Will you please explain Sheet 1 of Schedule 2 of Hearing Exhibit 1?

A. That sheet shows for various time periods the actual or estimated compound annual growth rate of the annual volumes for total UDC. The time periods for which growth rates are shown are the historic period 1962 through 1969 and the future periods 1970 through 1975 and 1970 through 1980.

Q. Will you please explain Sheet 2 of Schedule 2 of Hearing Exhibit 1?

A. That sheet presents in the same form as Sheet 1 of Schedule 2 a summary of the actual or estimated compound annual growth rates of peak day volumes.

Q. Will you please explain Sheet 1 of Schedule 3 of Hearing Exhibit 1?

A. That sheet provides miscellaneous customer data for UDC such as the total number of customers, total retail sales in MMcf, annual use per customer and 1969 retail revenue for various customer classes for the total UDC.

Q. Will you please describe briefly the method used in computing the compound growth rates given in your Schedule 2?

A. The compound annual growth rate was determined using the least-squares method of correlation analysis. In making the correlation analysis a linear regression line was developed which best fit the logarithm of the actual data points. That linear regression line was then transformed to exponential form in order to determine the annual growth rate. A computer program based upon this technique was used to perform the actual calculations made in determining the growth rates given in Schedule 2.

Q. What conclusions did you draw from analysis of the data shown in your Exhibit?

A. Sheet 1 of Schedule 1 shows that additional annual and peak day supply is needed as early as 1970. The additional amount needed annually in that year is in excess of 72 million Mcf. This amount rises to 260 million in 1971, 463 million in 1972, 657 million in 1973, 824 million in 1974 and in excess of 1 billion Mcf in 1975. This needed amount rises to 2 billion Mcf in 1980. Similar peak day capacity is also needed. It is my opinion, however, that the amounts shown on this schedule are conservative.

Q. Why do you believe that the amounts shown on Sheet 1 of Schedule 1 are conservative?

A. I believe that the estimated gas requirements shown on that sheet are conservative because:

First, gas industry load projections historically have been understated.

Second, the growth projections as shown by both annual and peak day requirements in Schedule 2 are significantly less than recent

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historical growth rates and in my opinion the leveling off of residential appliance and space-heating saturation is not a sufficient justification. For example, the UDC compound annual growth rate in annual volume requirements for the period 1962-1969 is 6.37%. Although admittedly the year 1980 is a long way off, the similar estimated compound annual growth rate for the period 1970-1980 is 3.56% or nearly one-half of the historic rate.

Third, an order-of-magnitude estimate using data in reports by the FPC Fossil Fuel Resources Committee for Northeast, East Central, Southeast Regions dated May, 1968 and West Central Region dated March 15, 1968, shows that coal requirements for electric generation for the year 1975, in the states predominately served by UDC, aggregates approximately 184 million tons which corresponds roughly to 4 million MMcf of gas. One of the means of meeting the new air pollution regulations will be to use gas rather than coal as a boiler fuel. For example, if 25% of the above estimated coal requirements for electric generation were to be supplied by gas, the corresponding additional requirements for natural gas would be equivalent to 1 million MMcf. Such a requirement is very large, even when compared to the total annual gas requirement for all of UDC.

Fourth, in my opinion the enactment of air pollution regulations may vastly increase the natural gas requirements of industrial customers served by UDC members, especially in the short-run, until engineering and research make available processes and equipment which permit those customers to again burn large volumes of coal or oil.

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PREPARED TESTIMONY OF F. W. BATTEN

Q. Would you please state your name and address?

A. Fred W. Batten, 120 E. 41st Street, New York, N.Y. 10017.

Q. By whom are you employed and in what position?

A. I am a Senior Vice-President and a Director of The Columbia Gas System, Inc. and the Columbia Gas System Service Corp.

Q. How long have you been employed in the Natural Gas Industry?

A. Since 1936.

Q. What is the area of your responsibility?

A. Since 1961 I have been chief operations officer of the System and my responsibilities include the development of System Gas Requirements and the procurement of gas supply to meet such requirements.

Q. Please describe generally Columbia Gas System's market area?

A. Columbia serves seven states extending from western Ohio and Kentucky to the Eastern Seaboard and the District of Columbia. Columbia serves about 1,770,000 meters at retail and it sells to over 100 utilities at wholesale which in turn serve about 2.3 million meters. Some of the major cities of the 1,300 communities served directly or indirectly are: Cincinnati, Dayton, Toledo and Columbus, Ohio; Frankfort and Lexington, Kentucky;

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Charleston, Wheeling and Huntington, West Virginia; Pittsburgh (part only), York and Harrisburg, Pennsyl-

vania; Richmond, Roanoke and Norfolk, Virginia; Baltimore and Hagerstown, Maryland; Binghamton, New York; Washington, D.C.

The market area of the System includes, in addition to major governmental centers such as Washington, Harrisburg, Charleston and Columbus, some of the most important industrial areas of our nation. Most of the thousands of industries depend upon gas for essential processing uses or as a raw material. The economic welfare of this large region depends heavily upon adequate supplies of natural gas.

Q. Were Columbia System's estimated requirements included in the composite data of the UDC Group presented on the record today?

A. Yes.

Q. Have you any coment to make on the System's future requirements incorporated in such data?

A. Yes, I would like to make one observation. The estimated requirements in such composite data were based upon the

[889]

System's May 1969 "Blue Book" which indicated that the System's natural gas requirements, excluding storage, would increase from 1.38 trillion cubic feet in 1970 to 1.54 trillion cubic feet in 1973. We estimated that by 1980 such requirements would total 1.91 trillion cubic feet annually, an increase of approximately 38% over 1970. Based upon more recent estimates, I am confident that the System's requirements estimate in the UDC composite data are conservative. Our most recent estimates indicate that the market requirements are substantially more than those included in the figures in the composite data.

[889]

Prepared Testimony of F. W. Batten

Q. What is the System's present situation with respect to meeting the requirements of these markets?

A. Based upon the 1969 May "Blue Book", we projected an expansion program that would have enabled us to meet the estimated requirements for the winter 1970-71. We have obtained certificates for such construction. By reason of the extremely cold weather we experienced this winter, our present storage position is such that we decided to apply for an additional 65,000 Mcf of capacity for the Columbia Gulf facilities. If this is certificated and the construction completed by November 1, it will help compensate for the deficiency we now forecast in storage as of November 1, 1970.

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However, in developing the System's 1970 May "Blue Book", our customers have supplied us with new estimates for the 1970-71 winter and subsequent years. These new estimates indicate requirements for the winter 1970-71 which are substantially greater than those given for the May 1969 "Blue Book." We will not be able to meet these increased requirements for the winter 1970-71 and we are so advising our customers.

Q. In other words Columbia cannot meet the full indicated requirements for the winter 1970-71?

A. That is correct.

Q. To what do you attribute these increases in requirements?

A. I judge, based upon various general reports that I have received, that the increased emphasis upon air pollution has caused a headlong rush by industry to get natural gas in place of present fuels. In addition, the electric power companies would like to use more gas in

their operations—in many cases for gas turbines so as to meet their steadily increasing requirements.

Q. Turning now to gas supply, would you describe the sources of supply for Columbia Gas System?

[891]

A. Prior to 1943, the System's source of supply was gas produced and purchased in the Appalachian area. Currently we obtain approximately 163 billion cubic feet or about 12% of our total requirements from the Appalachian area.

Since 1943, we have purchased, under long term contract, from all the major pipelines serving the Northeastern part of our country. In 1969 we purchased under these contracts the following volumes: 155,413,564 Mcf from Texas Eastern Transmission Corporation, 286,295,-379 Mcf from Tennessee Gas Pipeline Company, 96,544,-519 Mcf from Texas Gas Transmission Corporation, 65,-354,920 Mcf from Panhandle Eastern Pipeline Company, 31,325,302 Mcf from Transcontinental Gas Pipeline Company.

In 1954 Columbia arranged for the construction of a new pipeline, Gulf Interstate from southern Louisiana into its market territory. It subsequently acquired this pipeline in 1959, and renamed it Columbia Gulf. This pipeline transports gas purchased in southern Louisiana by United Fuel Gas Company, one of our subsidiaries. In 1969, it delivered 484.7 billion cubic feet of gas to our service area.

Q. In connection with your requirements for the winter 1970-71, did you seek individual additional volumes from your non-affiliated pipeline suppliers?

[892]

A. Yes, as a matter of fact, since 1968 we have been unsuccessful in obtaining significant additional volumes from these pipelines.

[892]

Prepared Testimony of F. W. Batten

Q. Would you describe your efforts to obtain additional reserves for your Columbia Gulf facilities?

A. Yes, Columbia Gulf maintains a Staff in its Houston office consisting of Lawyers, Geologists and Executives which is constantly trying to purchase gas from southern Louisiana producers. The attempts to keep abreast of exploration and development activities in the Southern Louisiana area and tries to purchase gas from wherever it is available, including the offshore area. During the past few years, we have been able to purchase some volumes of gas in that area but the volumes have been small by comparison to our need.

In 1963 we were able to purchase 6.1 trillion cubic feet of gas from Humble Oil and Refining Company to be delivered over a period of 23 years.

Subsequent to the execution of the Humble contract, we have been unable to obtain any substantial quantities of gas. The acquisition of gas in the southern Louisiana and offshore areas has become increasingly difficult each year.

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Q. Would you please state what reserves you have obtained since 1964.

A. In 1964 we were able to acquire 48 billion cubic feet of additional reserves; in 1965, 8 billion cubic feet; in 1966, 91 billion cubic feet; in 1967, 31 billion cubic feet; in 1968, 2 billion cubic feet. In 1969, as a result of being able to pick up reserves in four fields in the offshore area in which Preston Oil Company, an affiliate, had a substantial interest, we were able to add 572 billion cubic feet of reserves. These reserves represent

in large measure the exploration and development efforts that we initiated and have continued since 1962.

Q. What has the trend of your reserves been?

A. Despite the reserves added, the fact is that in 1964 we had 9.8 trillion feet of reserves; at the end of 1969 we had 8.1 trillion feet.

Q. What efforts have you made to produce gas in the southern Louisiana area?

A. Prior to 1960 we began developing reserves in the southern Louisiana area through Preston Oil Company. In 1962 we started acquiring offshore leases in joint ventures with non-affiliated companies. Our total investments in that

area (including offshore Texas) amounted to more than $60 million at the end of 1969. We started receiving gas from our onshore Louisiana production in 1960. The first deliveries of gas from our own production in the Gulf were in February 1970. As of November 1, 1970, we will be delivering into the Columbia Gulf line, from production properties in which Preston Oil Company owns an interest—approximately 170 million cubic feet per day.

Q. Do you have any observations with respect to the future gas supply requirements of Columbia Gulf?

A. Yes, when the present expansion program is completed, the capacity of the pipeline will be approximately 1.9 billion cubic feet per day. To replace gas transported through the line, we will require approximately 700 billion cubic feet per year. If this facility were expanded to meet the requirements of our market, still greater volumes would be needed.

Q. What efforts have you made to increase supplies in the Appalachian area?

A. Columbia companies have been producing natural gas in the Appalachian area since before 1900. During

1959, they produced 65 billion cubic feet in that area. In 1969 they

[895]

produced approximately 66 billion cubic feet in the Appalachian area. Most of the gas produced in the Appalachian area in the past has come from comparatively shallow wells. In an effort to find more gas in this area, Columbia has embarked on an intensive exploration effort including a deeper drilling program and expects to spend approximately $18 million over the next three years in an effort to find more gas in this area. These figures cover only exploration, leasehold acquisitions and geo-physical activity.

In addition to our own efforts at production we have purchased all of the gas that we could in the Appalachian area. For example, our annual purchases from 1959 through 1967 range around 70 billion cubic feet a year from independent producers. In 1968 such purchases were 95 billion cubic feet and in 1969 were 97 billion cubic feet. We are hopeful that with a prompt disposition of the Appalachian area rate proceeding there will be additional exploration and development, especially in the deeper horizons, by independent producers.

Q. Have you attempted to obtain gas from any other areas?

A. Yes. We have contracted to purchase approximately 300,000

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Mcf per day of liquefied natural gas from El Paso Natural Gas to be imported from North Africa.

Q. When will this LNG become available?

A. While we have negotiated with El Paso looking toward LNG deliveries by 1973, a more realistic estimate would indicate that no substantial amounts of LNG

will be available prior to 1974. We are also in preliminary negotiations for another additional source of LNG which I am not free at this time to discuss in detail. The receipt of LNG does not reduce the urgent need for additional reserves in southern Louisiana.

Q. Mr. Batten, could you summarize your general views as to what is necessary in order that the Columbia Gas System will be able to continue to meet its requirements at the 1970 level? In other words, assuming no growth beyond 1970 in your market requirements?

A. We must assume that the System's non-affiliated pipeline suppliers will be able to continue to meet their full contractual obligations to us. Insofar as such pipeline suppliers require additional reserves from the Southwest to maintain deliverability, it is essential that substantial additional volumes of gas become available to them.

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Many of our suppliers depend heavily on the south Louisiana area and for this reason efforts to encourage the exploration for and development of new reserves in this area are essential to our pipeline suppliers.

Insofar as Columbia Gulf is concerned, our present reserves of approximately 8 trillion cubic feet will not provide adequate deliverability commencing in 1973-74. Thus, it is essential that substantial additional reserves be contracted for and attached to our facilities no later than the early part of 1972. A large number of the contracts entered into in 1954 have now reached the point where there is a sharp decline in deliverability from the reserves dedicated under those contracts. As a minimum, I would state that we should contract for 700 billion feet of new reserves each year commencing in 1972 at

the latest, and preferably in 1971. I would like to emphasize in making this summary that our market requirements for this coming winter 1970-71 are not being fully met. Finally, I would point out that even if we could promptly dispose of this proceeding within the next month or two, at area rates that would afford producers an incentive to explore and develop new reserves, it is unlikely that any substantial reserves would be available prior to 1972. I

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make this statement on the basis of our experience that it takes a considerable time even after leases are obtained to do the necessary exploration for and then development of the new reserves.

Q. Do you have any recommendations that you think would help solve Columbia's gas supply problems?

A. I believe that it is essential to have certain and fair prices for gas in the field at an early date if we are to have an adequate supply. The uncertainty of the price to be received in past years has contributed materially, in my opinion, to the diminishing gas supply in the Louisiana area. We know that the required exploration and development effort will not be undertaken until the uncertainty as to whether a satisfactory price will be permitted is resolved.

For this reason, a prompt settlement of this proceeding is essential. We must settle it on the basis of prices which will afford proper incentives. I think the same thing holds true for the Appalachian area and I hope that the Commission will resolve that proceeding promptly. Finally, the Commission should use its prestige to impress upon other government departments the necessity for leasehold sales in offshore Louisiana at the earliest possible time.

Prepared Testimony Of H. D. Borger

[900]

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL POWER COMMISSION

AREA RATE PROCEEDING
(SOUTHERN LOUISIANA)

Docket No. AR69-1

PREPARED TESTIMONY OF H. D. BORGER

Q. Please state your name, position and address.

A. My name is H. D. Borger. I am Chairman of the Board and Chief Executive Officer of Consolidated Natural Gas Company. My office address is 4 Gateway Center, Pittsburgh, Pennsylvania.

Q. Please briefly identify Consolidated Natural Gas Company and its business.

A. Consolidated Natural Gas Company is a registered public utility holding company, holding all of the stock of a group of operating public utility companies providing gas service to both retail and wholesale customers in Ohio, Pennsylvania and West Virginia and to wholesale customers in New York. These companies serve almost 1,400,000 customers at retail and another 800,000 customers through wholesale sales to other utilities. The principal cities dependent on the Consolidated System for natural gas utility service are Cleveland, Akron, Canton, Youngstown and Lima in Ohio; Pittsburgh, Johnstown and Altoona in Pennsylvania; Clarksburg, Fairmont, Morgantown and Parkersburg in West Virginia; and Albany, Syracuse and Rochester in New York. The System supplied 813,010,000 Mcf of natural gas to its customers in 1969 at a total revenue of $542,168,303.

[901]

Prepared Testimony Of H. D. Borger

[901]

Q. Please state your experience with the Consolidated Natural Gas System.

A. I have been employed by the Consolidated Natural Gas System Companies for 48 years. For most of this time, I served with the operating companies, becoming President of The Peoples Natural Gas Company, a subsidiary of Consolidated, in 1955. In 1962, I became Senior Vice President of Consolidated Natural Gas System Service Company and, thereafter, served as Executive Vice President of both the service company and the holding company, becoming President of each in 1964. In 1966, I became Chairman of the Board of both companies. Continuously since 1962, one of my principal responsibilities has been and is the development and maintenance of adequate supplies of natural gas with which to meet the utility obligations of both the operating companies in the Consolidated System and of its wholesale customers.

Q. Please describe briefly the history of the Consolidated Natural Gas System and the methods by which it has secured its natural gas supplies.

A. The Consolidated System Companies commenced utility operations in the late 1800s based upon supplies produced and purchased in the local gas fields in Ohio, West Virginia and Pennsylvania. From these beginnings until 1943, all of the natural gas supply for Consolidated's utility markets in Ohio, Pennsylvania and West Virginia was drawn from the Appalachian natural gas fields in those States.

During World War II, it became apparent that the supplies in the Appalachian gas fields had become insufficient to carry the utility loads, and, in 1943, a connection was made for the purchase of gas from Pan-

handle Eastern Pipe Line Company. This was the first importation of midwestern natural gas supplies into the Appalachian Area. As the needs increased, purchase of gas from Tennessee Gas Transmission Company was commenced in 1944, from Texas Eastern

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Transmission Corporation in 1947, from Transcontinental Gas Pipe Line Corporation in 1960 and from Texas Gas Transmission Corporation in 1968. Appalachian supplies have remained relatively static in amount since the 1940s, and all of the natural gas with which to meet growth in Consolidated's utility demand has been imported from the midcontinent, Texas and Louisiana gas fields.

At the present time, the Consolidated System is purchasing gas under firm long-term contracts at the daily rates of: 656,858 Mcf from Tennessee, 185,000 from Panhandle, 698,511 from Texas Eastern and 306,000 from Texas Gas Transmission. All of these suppliers deliver gas to the System at 100% load factor throughout the year. The supplies purchased from Transcontinental are in the form of annual quantities purchased for storage and, on an average-day basis, they amount to only 27,341 Mcf per day. All of the supplies from the pipeline suppliers are purchased under long-term contracts, with most contracts being for a period of 20 years. The aggregate quantity of firm gas to be purchased under long-term contracts from these five suppliers in 1970 will amount to just over 642 Bcf.

In 1969, the System acquired West Ohio Gas Company, which secures the bulk of its supply from Ohio Fuel Gas Company, a subsidiary of the Columbia Gas System. However, since West Ohio is not presently in-

terconnected with the balance of the System, its gas supply and requirements will not be included in the balance of my testimony. It should be noted that Ohio Fuel has requested West Ohio to limit its future industrial sales.

Q. Mr. Borger, will you please describe the customary manner in which the Consolidated System Companies have, over the years, arranged for gas from these pipeline suppliers.

[903]

A. The estimated future requirements and supply situation of the System is carefully studied on a continuing basis. From these estimates, the additional amounts which must be contracted for to meet the growth in consumer demand each year are determined and the company then, normally a year or two in advance, enters into contracts with one or the other of its pipeline suppliers for necessary increments in supply. Sometimes, contracts are made for a single year's increment in supply; sometimes, the contract will cover two or three annual increments on a step-up basis. As a normal rule, each time an increment is added to the imbedded contract amount, the whole amount as so increased is covered by a new long-term contract at the enlarged quantity.

Q. Prior to this time, was there ever any difficulty in arranging for these annual increments as they were required?

A. Yes. In the late 1940s and early 1950s, the pipelines were having difficulty building capacity fast enough to comply with the then tremendous increase in the distribution markets, and, in the late 1950s, there were delays in pipeline construction due to legal complications. But at no time was there any problem as to the

availability of underlying supply in the field, and, as soon as capacity was constructed, supplies for the distribution market were adequate.

Q. Please now discuss the events leading up to the situation in 1968.

A. In 1965, negotiations were started with Texas Gas Transmission Corporation for an additional supply of gas through a new pipeline connection to its system. The negotiations were completed in 1966 but the signing of the Precedent Agreement was delayed until January 12, 1967, waiting for Texas Gas to secure commitments of the necessary supplies in the field. This was the first indication from any of our suppliers that they were having any trouble buying gas in the production fields.

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During the early months of 1968, the company engaged in supply conversations with those suppliers who had intervened in the certificate proceeding involving the purchase from Texas Gas Transmission Corporation. At the time of those conversations, there was no indication of any problem in purchasing future increments of additional supply from those suppliers. On the contrary, there was every indication that they had plentiful supplies to offer.

During the fall of 1968, the company initiated conversations with its suppliers relative to additional annual increments of supply to commence in late 1969 and 1970. We found to our amazement, however, that none of our suppliers were able to enter into any enlarged contracts. In part, the reason given was that they were having difficulty in arranging for the purchase of necessary additional supplies from producers in the field; and, in part, the reason had to do with the low return allowed

by the Federal Power Commission in relation to materially-increased interest costs, thus making it difficult to justify expansion of pipeline capacity. As the fall of 1968 progressed, we found from conversations with other distribution companies that they were having similar difficulty in arranging for additional increments from pipeline supplies.

The only additional gas we were able to obtain was 40,000 Mcf per day from Tennessee on a year-to-year basis. We were also able to make some spot purchases of summer gas for injection into storage.

Q. What happened during 1969?

A. All during 1969, my associates and I continually requested our pipeline suppliers for additional increments of supply. While we were able to purchase significant volumes of a spot off-peak basis due to the load factors existing on our pipeline suppliers, we were unable to contract with our suppliers

[905]

for any additional long-term supplies. We were routinely met with the response that there was a shortage of gas for purchase in the gas fields in Texas, Louisiana and the midcontinent areas of the United States. As the year progressed without success in purchasing additional firm gas, our System curtailed our promotion of new large-volume commercial and industrial sales, and discouraged sales above certain quantities.

Q. Please describe the situation during the past winter.

A. The System entered the past winter with approximately 115 MMcf per-day less firm flowing supply on a long-term basis than it should have had, due to our inability to purchase necessary increments of firm gas

from our pipeline suppliers. The winter also proved to be a very severe one. In consequence, in order to meet the heating loads of our residential and commercial customers in full, we were forced to make large-scale industrial curtailments on a total of eight days. Also, to protect our markets, we arranged with certain large industrial customers who had standby to shift to oil for the remainder of the winter season at a higher cost which was borne by the Consolidated System, these customers cutting back some 70 MMcf a day.

Q. Mr. Borger, what is Consolidated's present gas supply situation?

A. Based upon our most recent estimate of requirements for the winter of 1970-1971, and taking into consideration the unusually large withdrawals from storage during the past winter occasioned by the severe weather we have experienced, the Consolidated System will require 200,000 Mcf per day long-term firm supply above amounts already contracted for on November 1, 1970. To date, we have been unable to contract for any of the 200,000 Mcf per day that would be required, although we are depending on the continuation of the 40,000 Mcf per day that we have been receiving from Tennessee on a year-to-year basis.

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Summer gas required during the summer of 1970 to fill our storages to their developed capacity at October 31, 1970, amounts to 55 billion feet. If we are able to obtain this amount of summer storage gas, the flowing supply required November 1, 1970, would be reduced to 40,000 Mcf per day which we are relying on receiving through continuation of the Tennessee short-term delivery. We are making every effort to secure this summer gas from whatever source may become available,

including continuing some of our large industrial customers on oil standby on a voluntary basis at an anticipated rate of 70,000 Mcf per day, although we are advised that low sulfur content fuel oil is currently in relatively short supply in the Cleveland area. I should note that our storage deficiency would have been 5 billion cubic feet greater had it not been for the oil standby arrangements we made between January 16, 1970, and March 31, 1970.

Q. What other steps are being taken by Consolidated in view of this very serious supply shortage?

A. In order to protect out existing customers and to meet normal growth in our residential markets, we are making every effort to control our volume of industrial sales, within the limits of available supplies, at roughly their present levels. Thus, we are discouraging new industrial sales and urging installation of dual fuel facilities.

In the commercial market, we are cutting back many sales activities and discouraging certain types of sales in order to control and maintain the rate of growth of commercial sales within the amounts reflected in our current sales estimate.

We have been and are continuing to seek all possible arrangements to obtain additional volumes of gas on a short-term basis, even though such purchases do not satisfy our needs for long-term supply.

[907]

Q. What will be the supply requirements in the years immediately following the winter of 1970-1971?

A. Assuming that we are able to contract for 200,000 Mcf per day commencing November 1, 1970, we will

need at least an additional 75,000 Mcf per day each November 1st for the next four years to meet our historical market growth but exclusive of any unusual market opportunities that may be caused by pollution regulations.

Q. Have you made any effort to determine whether there is, in fact, a current gas shortage in the field?

A. Since our problems commenced in 1968, we have examined the subject in depth in consultation with independent consultants. In our opinion, the falling off of drilling activities over the past several years and the marked acceleration of the national demand for gas, due, in part, to increased concern over air pollution, and artificially low prices both in the field and in the consumer market have resulted in a serious current gas shortage. Hindsight now shows that the shortage was probably foreshadowed several years ago and my conclusion now is that the volumes of undedicated reserves which may be available for purchase by the pipelines are insufficient to meet current increases in utility demand.

Q. Mr. Borger, are you attempting to answer the problem of the System in part through stepping up supplies from the Appalachian Area?

A. Yes. Our Companies are enlarging their own drilling operations in the local fields to the fullest extent practicable, and we have also increased the price at which we will purchase new supplies of gas from the local independent producers. These efforts will somewhat increase these local supplies but, based on our long experience, we know that it will be impossible to secure from this area the additional increments of gas which are needed to meet the growth in the utility demand by consumers in the territory we serve.

Q. Mr. Borger, has the Consolidated System given any thought to meeting the supply problem through the gasification of coal?

A. Yes. The Consolidated System and others are carrying on research with regard to the development of economically-feasible gas manufactured from coal. Our research effort in this regard has proceeded for more than ten years. We now anticipate that gas from this source should be on line in material quantity in five to seven years, but at a price considerably higher than the present price of gas from domestic sources. This alternate is distant in time and provides no answer to the immediate shortage.

Q. Have you been studying the acquisition of alternate supplies of liquefied natural gas from foreign countries?

A. Yes. We have been studying this matter in great detail and are participating with two of our pipeline suppliers in their project for importing substantial volumes of liquefied natural gas. Here again, the delay will be several years and costs will be considerably higher than natural gas from domestic sources. This is not an answer to the immediate shortage.

Q. Have you been attempting to secure additional supplies of natural gas from Canada?

A. Yes. We have been attempting for over a year to buy gas from Trans-Canada and within the past two weeks we were able to enter into an arrangement which we expect will provide us with about 19 MMcf per day beginning in 1972 and increasing to 38 MMcf per day in 1974. This arrangement is subject to approval of Canadian and United States regulatory agencies and, if approved, will cost considerably more than gas from

domestic sources. Moreover, as the quantity expected from Canada is increased, both the time lag and costs can be expected to increase.

[909]

Q. Mr. Borger, in your opinion does the regulation which has been imposed since 1954 by the Natural Gas Act upon the producers have any bearing upon the current gas shortage?

A. Yes. I am convinced that necessary new supplies are not available for purchase by interstate pipelines in large part because of the cumulative effects of regulation under the Natural Gas Act during the period since the *Phillips* decision in 1954. In my opinion, price reductions and price rollbacks and instability have stifled exploration operations while the resulting low rates have created an artificially-high demand for natural gas. Low interstate rates have made it possible for intrastate industrial customers to outbid the interstate pipelines all along the Gulf Coast; and, finally, the administrative burden of selling gas in interstate commerce and getting involved in rate and certificate cases has caused the producers to sell gas in interstate commerce only when they could not use it themselves or sell it intrastate.

Q. What do you believe to be the steps necessary to the solution to the interstate supply problem?

A. There must be a tremendous enlargement in the exploratory efforts of the producing industry throughout the Louisiana, Texas and other midcontinent areas, and this, in my opinion, can be brought about only through a reversal of past trends of policies and the establishment of prices which will encourage and bring about this activity. To this end, I believe it is necessary that the

Commission, at the earliest possible moment, adjust the prices established in Opinion No. 546.

Q. Do you believe that such price adjustments are compatible with the best interests of the consumer?

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A. Yes. Natural gas is an ideal form of energy for many domestic, commercial and industrial utility purposes, and the consumers of this nation are demanding a steady enlargement in this service. They have already invested millions of dollars and are proposing in the future to invest additional millions in appliances for which assured long-term supplies are essential.

Since full, adequate and timely supplies cannot come at this time from L.N.G. or Canada, or from the gasification of coal, and since, when they do come, supplies from these alternate sources will be substantially higher in cost than current costs for domestic suplies, both the public interest and the interest of the consumers in this country, in our opinion, require the payment of such higher prices as will bring about the development of larger domestic gas reserves. Nor can we afford to spend another nine years arriving at the wrong answer. The need is immediate and imperative.

I would further point out that, from the standpoint of both balance of payments and complete assurances of access to supply, it is better for the nation to develop and rely upon domestic resources to the fullest extent practicable rather than to follow the path, which will surely result from past regulatory policy, of squeezing our domestic resources in favor of greater and greater reliance on imports.

April 1, 1970

[912]

TESTIMONY OF HERBERT D. CLAY

In Matter of
AREA RATE PROCEEDING
(OFFSHORE SOUTHERN LOUISIANA)
Docket No. AR69-1

Q. Mr. Clay, would you please state your full name and address for the record?

A. My name is Herbert D. Clay; my business address is 10 Lafayette Square, Buffalo, New York.

Q. By whom are you employed and in what capacity?

A. I am President of the National Fuel Gas Company and of one of its subsidiaries, Iroquois Gas Corporation.

Q. Could you describe the National Fuel Gas Company?

A. National Fuel Gas Company is a registered public utility holding company with its stock listed on the New York Stock Exchange and subject to regulation by the Securities and Exchange Commission. It owns 100% of the capital stock of Iroquois Gas Corporation, the Pennsylvania Gas Company, United Natural Gas Company and Producers Gas Company. National Fuel also owns 100% of the capital stock of a number of smaller nonutility production and storage companies.

[913]

Iroquois, Pennsylvania Gas and United Natural are distribution subsidiaries of National Fuel. Their service territory includes portions of western New York, Pennsylvania and a small portion of Ohio.

United Natural Gas Company is operated to some extent as a storage and supply company for National's

distribution system and its interstate rates are regulated by the Federal Power Commission.

Q. Mr. Clay would you describe the distribution territory of the National Fuel Gas System?

A. Iroquois Gas Corporation distributes gas in all or portions of the counties of Niagara, Erie, Chautauqua, Cattaraugus, Allegany, Steuben, Wyoming, Genesee, Livingston, Monroe, and Ontario, New York. The Pennsylvania Gas Company distributes gas in all or portions of the counties of Erie, Warren, McKean, Forest, and Elk, Pennsylvania, and Chautauqua, and Cattaraugus counties, New York. United Natural Gas Company distributes gas in all or portions of the counties of Armstrong, Butler, Cameron, Clarion, Clearfield, Crawford, Elk, Erie, Forest, Jefferson, McKean, Mercer, Venango, and Warren, Pennsylvania, and Ashtabula and Trumball, Ohio.

The distribution territory of the National Fuel Gas distribution companies includes the Buffalo Niagara Falls

metropolitan area and the smaller metropolitan centers of Erie and Warren-Sharon Oil City, Pennsylvania, and Jamestown, New York.

Q. What is the population of the area served by the National Fuel Gas distribution companies?

A. Approximately 2,300,000 people. We have approximately 635,500 customers.

Q. What volume of retail sales did the National Fuel Gas distribution companies have in 1969?

A. In 1969 the National Fuel Gas distribution companies had retail sales of 217,001 MMCF (at 14.73 psia). 1969 retail revenues amounted to $169,235,000.

Q. Where do National Fuel's distribution subsidiaries, Iroquois and Pennsylvania Gas, obtain the gas sold to retail customers?

A. National Fuel's distribution companies purchase natural gas from a number of major pipeline suppliers, including Tennessee Gas Pipeline Company, Texas Eastern Transmission Company, Consolidated Gas Supply Corporation, Transcontinental Gas Pipeline Company, Manufacturers Light & Heat Company and the Valley Gas Transmission Company. Our companies also purchase gas directly in Texas from Shell Oil

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Company and other producers and from the Valley Gas Company and contracts to have this gas transported by Tennessee Gas Pipeline Company.

Recently, the National Fuel distribution companies have negotiated the purchase of additional natural gas from Canada. This gas is purchased from Tennessee Gas Pipeline Company and from Trans Canada Pipelines Limited.

Q. Mr. Clay, why are you presenting testimony and exhibits in this case?

A. I am participating in this case because I am convinced that a serious shortage in our national gas supply has developed, and I foresee that unless prompt action is taken to alleviate this shortage the National Fuel Gas distribution companies will be unable to acquire sufficient supply to meet the demands that will be made on them by their customers in the 1970's.

Q. How much growth do you see in the demand that will be experienced by the National Fuel Gas distribution companies in the 1970's?

A. In 1970, our demand will be approximately 238,400 MMCF. I anticipate a steady increase in this de-

mand to a total 319,400 MMCF by 1980. The specific increase

[916]

in demand that we project is shown in detail on a year-by-year basis on schedule 1 of exhibit 2.

Q. Does the growth pattern that the National Fuel distribution companies experienced during the 1960s lend support to your projections of demand during the 1970s?

A. Yes it does. As shown on schedule 3 of exhibit 2, in 1962, the annual requirements of the National Fuel distribution companies were approximately 160,000 MMCF. A steady increase in these requirements was experienced as shown on sheet 3 of schedule 2, until our annual requirements reached approximately 224,000 MMCF in 1969. Thus, between 1962 and 1969 we experienced an increase in demand of approximately 40%.

Q. What are some of the major factors involved in the growth of demand that you forecast?

A. Our service territory is experiencing significant economic growth. This is especially true of the Buffalo metropolitan area. During the 1970's a huge new development involving the State University of New York and the New York State Urban Development Corporation will rise at

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Amherst near Buffalo. This new complex will significantly add to the demands that we would anticipate through normal economic growth of our service area. Additionally, the growing awareness of the problem of air pollution control can be expected to result in an increased demand for natural gas through advancing development of the fuel cell and other total energy concepts.

Q. With the increased demands that you have outlined in mind, what is the picture as to the supply that the National Fuel distribution companies can obtain to meet these demands?

A. As shown on schedules 2 and 3 exhibit 2, the deficit between projected demand and supply contracted for is 12,425 MMCF in 1971 and steadily increases to 115,400 MMCF by 1980.

Q. What factors tend to reinforce your assessment that National Fuel may be unable to contract for the additional supplies for which no commitments have thus far been obtained, to meet the anticipated demands for the 1971-72 heating season?

A. Our experience indicates that it is necessary to contract several years in advance for the supply that we predict will be necessary. As of now, we have been

unable to get adequate commitments for the 1971-72 heating season. It is my considered judgment that unless something is done to alleviate the present shortage of gas in the areas where we obtain our supplies, there is nothing we can do to fill the indicated deficiency between demand and supply for the 1971-72 heating season and for subsequent years.

Q. Mr. Clay could you summarize the position of National Fuel in this proceeding?

A. As I have indicated, the National Fuel Gas Company is convinced that there is, and will continue to be if present conditions persist, a gap between the demand on the National Fuel Gas distribution companies and the supply of gas that we can obtain during the 1970s. We feel strongly that the gas supply problem is a grave and serious one, and that prompt Commission action to alleviate this shortage is imperative.

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PREPARED TESTIMONY OF H. E. FORD

Q. Will you state your name and address, please.

A. H. E. Ford, 914 Keystone Avenue, River Forest, Illinois.

Q. What is your occupation?

A. I am Senior Vice President—Administration of Northern Illinois Gas Company.

Q. What is your educational background, Mr. Ford?

A. I am a graduate of the University of Illinois, from which I received a degree of Bachelor of Science in Commerce in 1927.

Q. What is your business experience?

A. I have been employed in public utility work for over forty years, with the exception of approximately three years service in the Navy during World War II.

On graduation from college, I had various assignments with Northern Illinois Gas Company and predecessor companies until 1956.

In 1956, I was made Assistant to the President of Northern Illinois Gas Company and Vice President of NI-Gas Supply, Inc., a subsidiary. In the latter position, I organized and started that Company's operations in oil and gas exploration and production.

On February 18, 1958, I was elected Vice President (Supply) of Northern Illinois Gas Company, responsible for determination of the overall

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supply of gas required, the procurement of gas supplies, and administration of certain matters relating to bulk

sales of gas, and recommendations with respect to additional production or storage capacity within the system. I continued to be responsible for the operation of NI-Gas Supply, Inc.

My title was changed to Vice President—Procurement on January 1, 1963, and my responsibilities were expanded to include operation of the Company's transmission and storage facilities and general purchasing and stores activities.

On June 3, 1969, I became Senior Vice President—Administration, which position I now hold, and I am responsible for the duties previously described as well as certain others.

Q. Will you describe briefly the operations of Northern Illinois Gas Company.

A. Northern Illinois Gas Company is an Illinois public utility distributing gas in the northern part of the State of Illinois generally outside of the City of Chicago, serving over 1,040,000 customers in an area of about 18,000 square miles. Its natural gas supply is purchased from four major pipelines—Natural Gas Pipeline Company of America, Midwestern Gas Transmission Company, Northern Natural Gas Company and Panhandle Eastern Pipe Line Company. The total daily contract quantities as of November 1, 1969, were 1,380,612 Mcf. Northern Illinois also purchases storage service from Natural Gas Pipeline Company of America and Midwestern Gas Transmission Company, and has substantial quantities of gas stored in its own squifer storage fields. On December 31, 1969, Northern Illinois had 130 billion cubic feet of total gas in storage in its own fields or stored by the pipelines for future delivery to it.

Prepared Testimony of H. E. Ford

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Q. What are the estimated future requirements for natural gas for Northern Illinois?

A. The data furnished by Northern Illinois, which are included in the total figures to which Mr. Sarikas will testify, show an anticipated peak-day growth in the next ten years averaging slightly over 200 million cubic feet per year. With our extensive use of storage, our experience has indicated that our most efficient operation occurs when we supply approximately one half of our peak-day requirements from pipeline flow gas and one half from storage. On this basis, we expect to require at least 100 million cubic feet per day additional pipeline flow gas each year in the immediate foreseeable future.

Q. What arrangements have you with your pipeline suppliers for this additional gas?

A. We signed a Precedent Agreement with Natural Gas Pipeline Company for an additional supply of 93 million cubic feet per day in the fall of 1970. Of this amount, approximately 37 million will come from additional supplies on Natural's "Amarillo" line and 56 million cubic feet per day is proposed to be purchased from Canada. Neither of these two supplies has been certificated by the FPC yet. At the same time that we were talking with Natural about this additional gas, we talked to our other pipeline suppliers and were unable to secure a commitment from them for supplies for 1970. For the years after 1970, we have been unable to secure any commitment from any of our pipeline suppliers. In other years, we have been well along by March in agreeing with our suppliers on a program for delivery eighteen months thereafter. Each of them is aware of our

continuing annual incremental requirements, but their position so far has been that they are not able to make

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any commitments at this time, principally because of uncertainty as to their ability to acquire new reserves sufficient to replace current deliveries and to provide for load additions. At the present time, our best prospects appear to be possible new supplies imported from Canada. The cost of such supplies, of course, is increased by the very long transmission distances involved.

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Testimony of J. B. Simpson

[925]

UNITED STATES OF AMERICA
FEDERAL POWER COMMISSION

CONSUMERS POWER COMPANY

TESTIMONY OF J. B. SIMPSON

Q. Please state your name and address.

A. J. B. Simpson, 212 West Michigan Avenue, Jackson, Michigan.

Q. Please state whether you are employed by Consumers Power Company and in what capacity.

A. I am a Senior Vice President of Consumers Power Company in charge of gas operations.

Q. Please state your educational background and business experience with Consumers Power Company.

A. I am a graduate of the Massachusetts Institute of Technology and hold a Bachelor of Science Degree in Petroleum Engineering. I was employed by Consumers Power Company in 1946 as a Junior Engineer in the Gas Department. In 1947, I was transferred to Michigan Gas Storage Company, a subsidiary of Consumers Power Company, and in 1951 I became Assistant General Superintendent of Michigan Gas Storage Company. In December 1952, I returned to Consumers Power Company and was appointed General Supervisor of Gas Operations for Consumers Power Company. In 1958, I was appointed Vice President in charge of gas operations of Consumers Power Company and Vice President of Michigan Gas Storage Company. In

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1968, I was appointed to my present position as Senior Vice President in charge of gas operations of Consumers Power Company.

Q. Are you a registered engineer and a member of any professional societies or associations?

A. Yes. I am a registered engineer in the State of Michigan, and I am a member of the American Gas Association, the National Association of Corrosion Engineers, the American Institute of Petroleum Engineers, the Michigan Society of Professional Engineers and the Michigan Engineering Society.

Q. What are your principal duties as Senior Vice President of Consumers Power Company and Vice President of Michigan Gas Storage Company?

A. I am in charge of the gas operations of Consumers Power Company and the operations of Michigan Gas Storage Company. It is my responsibility to review the market requirements of both companies, obtain gas supplies, and to supervise and plan the engineering, construction, operation and maintenance of the gas systems of both companies.

Q. Please briefly describe the nature of the business of Consumers Power Company.

A. Consumers Power Company is a public utility engaged in the electric and gas business in the State of Michigan. The natural gas business of the Company is rendered in a service area consisting of all or parts of 40 counties in the central and southern

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parts of the Lower Peninsula of Michigan. This service area covers over 12,700 square miles and has a population of over 3,000,000 people. The Company renders gas service to more than 830,000 customers within this service area. The principal communities served with gas include Bay City, Flint, Jackson, Kalamazoo, Lansing, Pontiac, and Saginaw. There are a number of other cities

served by the Company that have grown to substantial size in recent years, particularly in Macomb and Oakland Counties and the western part of Wayne County.

The Company supplied 279,769,000 Mcf of natural gas to its retail customers in 1969 and received therefor total revenues of $236,670,000.

Q. Please describe briefly the history of Consumers Power Company and the methods by which it has secured its natural gas supplies.

A. Consumers Power Company has been engaged in the gas business since 1922 and its predecessors manufactured and distributed gas in most of the principal cities now served by the Company approximately 100 years ago. Originally there were a number of utilities engaged in the production and sale of manufactured gas which were subsequently consolidated into Consumers Power Company. In 1931 following the discovery of natural gas in commercial quantities in Michigan, a portion of the Company's territory was converted to natural gas. Approximately ten years later the balance of the Company's service area was converted from manufactured to natural gas when Panhandle Eastern Pipe Line Company completed its interstate pipeline and

brought gas from the southwestern part of the United States into Michigan. For a few years following the completion of the Panhandle line, a portion of the Company's territory was served with Michigan gas and the balance with Panhandle gas. In 1945, it became apparent that additional supplies of natural gas were needed in the Company's service area. The requirements of the Company's customers were constantly increasing and the supply available from Michigan production was declin-

ing. As the then developed Michigan fields became depleted, the Company commenced negotiations with Panhandle for an additional supply of gas but as these negotiations progressed, it became evident that Panhandle's facilities would be insufficient to furnish the Company with the quantity of gas needed to meet the day-to-day requirements of its customers. However, because Panhandle did have excess gas available in the summer months, the possibility of purchasing gas during off-peak periods from Panhandle and storing it in previously depleted gas fields in Michigan for use in the winter months was discussed. The negotiations with Panhandle led to the creation of our subsidiary, Michigan Gas Storage Company, a Michigan corporation.

In 1946, the newly organized Storage Company entered into a contract with Panhandle for the purchase of increased quantities of gas. This contract has subsequently been replaced with contracts providing for larger deliveries. At the same time, Consumers Power Company entered into an agreement with Storage Company providing for the purchase of gas by Consumers Power from Storage Company. Consumers Power Company's purchases of gas from Storage Company

are made pursuant to a cost-of-service tariff which has been approved by the Federal Power Commission.

As the need for gas in Consumers Power Company's service area continued to increase, Consumers Power Company in 1959 entered into a gas service agreement with Trunkline Gas Company, a subsidiary of Panhandle Eastern Pipe Line Company. The volumes received by the Company from Trunkline have increased regularly since 1959 to meet the requirements of Consumers Power

Company's market area. The supply of gas available from Michigan production has remained relatively insignificant since the early 1930's and all of the natural gas with which to meet growth within Consumers Power Company's market area has been purchased from Panhandle Eastern Pipe Line Company by Michigan Gas Storage Company and from Trunkline Gas Company by Consumers Power Company. The gas supply provided by Panhandle and Trunkline has been imported largely from Texas, Oklahoma, Kansas and Louisiana gas fields.

At the present time, Michigan Gas Storage Company's contract with Panhandle provides for the delivery of 92,500,000 Mcf a year and Consumers Power Company's service agreement with Trunkline Gas Company provides for a daily rate of 600,000 Mcf. The contract with Panhandle Eastern Pipe Line Company provides for a daily contract demand during the months of January, February, March, November and December of 120,000 Mcf, and during the months of April, May, June, July, August, September and October of 105,000 Mcf. The balance of the gas volume required to be delivered by Panhandle to Storage Company amounts to 51,945,000 Mcf of annual contracted

volume of which 45,445,000 is required to be delivered in the seven warmer months of the year. The aggregate quantity of firm gas expected to be purchased under long-term contracts from these suppliers in 1970 is estimated to amount to 317.6 billion cubic feet.

Q. Mr. Simpson, will you please describe the customary manner in which Consumers Power Company and Michigan Gas Storage Company have, over the years,

arranged for gas from Panhandle Eastern Pipe Line Company and Trunkline Gas Company?

A. Consumers Power Company has a Gas Forecast Committee, of which I am a member, which analyzes extensive market data and determines the future gas sales requirements of Consumers Power Company. From the estimates compiled by the Gas Forecast Committee, the additional gas which must be obtained to meet the growth in the Company's market requirements each year is determined and the Company or Michigan Gas Storage Company enters into negotiations with Trunkline Gas Company or Panhandle Eastern Pipe Line Company for necessary increments in its gas supply. These negotiations have been followed by an agreement providing for the additional gas which will be required in the Company's service area. This agreement normally has been entered into approximately three years in advance of the time when the additional gas will be required. In recent years, the increments in gas supply have been obtained from Trunkline Gas Company. Over the past five years, 1965-1969, the annual increment to gas supply has averaged 75,000 Mcf per day. Each time an increment is added to the contract amount

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with Trunkline Gas Company, the whole amount as so increased is covered by a new long-term contract at the larger quantity.

Q. Prior to this time was there ever any difficulty in arranging for these annual increments as they were required?

A. Yes. As I previously testified, in the mid-40's Panhandle Eastern Pipe Line Company did not have sufficient capacity to meet the winter requirements of

Consumers Power Company and as a result Michigan Gas Storage Company was created so that gas could be purchased from Panhandle partially on an off-peak basis, placed in storage, and then used to meet the requirements of Consumers Power Company. In addition, in the 1950's, because of delays in pipeline construction, the Company was not able to obtain the annual increments in the supply it required and it was necessary at that time to impose restrictions on the addition of space-heating customers on the Company's system. However, at no time has there been any problem as to the availability of underlying supply in the field and as soon as pipeline capacity was constructed, the Company was able to obtain the incremental supply which it required to meet its market demand.

Q. Would you now discuss the Company's current gas supply situation and the prospects for additional supply over the next few years?

A. At the present time the Company's gas supply is adequate to meet the requirements of its market area and the Company has not placed any sales restrictions in effect. The Company has an agreement with Trunkline Gas Company which provides for the receipt of an

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additional 100,000 Mcf per day of gas commencing in November of this year, 50,000 Mcf per day commencing November 1, 1971 and 25,000 Mcf per day commencing November 1, 1972. The 100,000 Mcf per day of additional gas commencing November of this year is the subject of a certificate application which is presently pending before the Federal Power Commission. If the Company is able to obtain all of the additional gas from Trunkline Gas Company which it has contracted for,

the Company's gas supplies will be adequate to meet the needs of its market areas through 1971. Although a minor deficiency in annual supply will be experienced in 1971, this deficiency is not sufficiently large to cause any curtailments or sales restrictions. However, commencing in 1972, the Company's gas supply, based upon present contracted volumes, will be insufficient both on an annual and peak-day basis to meet the estimated growth in market requirements at that time. The supply deficiency on an annual basis will increase from over 22 billion in 1972 to over 133 billion in 1975 and to approximately 283 billion in 1980. The supply deficiency on a peak-day basis will increase from 50,000 Mcf in 1972 to 300,000 Mcf in 1975 and to 1,050,000 Mcf in 1980.

The Company has discussed its supply situation with its gas suppliers. The Company has not been able to contract with either Panhandle or Trunkline for any additional increments in gas supply over the increments which are presently provided for in the Company's contracts and which I just described. The inability to contract for

additional increments in gas supply results in the supply deficiencies which commence in 1972.

Q. Mr. Simpson, will you state why you believe the Company is confronted with a serious gas supply problem?

A. Needless to say the gas supply problem confronting the Company has been studied extensively by Company officials for some time. The basic reasons for the situation confronting the Company can be summarized as (1) an unprecedented increase in the demand for gas which has been brought about by concern over the

environment and a desire to lessen or eliminate air pollution caused by the burning of other fossil fuels and (2) the inability of the pipeline companies to obtain an adequate supply of gas to meet the growing requirements of the Company's market area because of the decline in producer drilling over the past several years.

Q. Mr. Simpson, do you believe that your supply problem could be solved through gasification of coal or the receipt of supplies of liquefied natural gas from foreign countries?

A. No. While gasification of coal and liquefied natural gas from foreign countries may form the basis of a gas supply in future years, at the present time such sources are not commercially practicable in the Company's service area and, therefore, afford no solution to the supply problem confronting the Company.

Q. Do you believe that your gas supply shortage could be alleviated by the securing of additional supplies of natural gas from Canada?

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A. The Company has studied the possibility of obtaining a gas supply from Canada for several years. I believe that the Commission is aware of the Great Lakes Pipeline project which brings Canadian gas into the State of Michigan. However, Canadian gas also affords no solution to the Company's current gas supply problem because at the present time all of the Canadian gas being delivered in Michigan has been committed and no additional quantities of Canadian gas are available for Michigan markets.

Q. Mr. Simpson, what do you believe is required to relieve the gas supply shortage confronting Consumers Power Company?

A. The solution which holds the most promise both in terms of time and economics is encouragement of drilling operations by producers in the United States. I believe that producers should be encouraged to carry on an expanded drilling program by being offered greater incentives than are provided by the producer prices currently in effect under Federal Power Commission regulation. An increase in producer prices which will result in the discovery of needed gas reserves obviously will serve the public interest.

Q. Mr. Simpson, have you prepared an exhibit which sets forth statistical data relating to the Company's gas operations and, in particular, its gas requirements and anticipated gas supplies?

A. Yes.

(Introduce Exhibit 3, "Consumers Power Company, Gas Market and Supply Data")

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Q. Mr. Simpson, do you have before you the exhibit which has been marked for identification as Exhibit 3 in this proceeding?

A. Yes.

Q. Was Exhibit 3 prepared by you or under your supervision?

A. Yes.

Q. Does Exhibit 3 show in summary form the serious gas supply shortage confronting the Company?

A. Yes. This is shown by sheets 1 and 2 of Schedule 2 of Exhibit 3. As shown on line 21 of sheet 1 of Schedule 2, the Company's annual gas supply will be adequate until 1972. While a minor deficiency will be experienced in 1971, as I have previously testified, this deficiency is not of sufficient magnitude to require any

curtailments in the Company's operations or sales programs. However, as can be seen from line 21, the deficiency in annual supply will increase from over 22 billion cubic feet in 1972 to almost 283 billion cubic feet in 1980. Referring now to the peak-day gas requirements, sheet 2 of Schedule 2 of Exhibit 3 shows that the Company's gas supply on peak days will be adequate through 1971 and that commencing in 1972 the Company will experience a deficiency. This deficiency will increase from 50,000 Mcf in 1972 to 1,050,000 Mcf in 1980. In addition, as I have previously testified, these deficiencies are, of course, predicated upon the assumption that the Company will receive the additional incremental volumes of gas which it has contracted for which amount to 100,000 Mcf per day commencing in November of this

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year, 50,000 Mcf per day in November 1971, and 25,000 Mcf per day in November 1972. Obviously, if the Company does not receive these incremental quantities, the deficiencies shown in Schedule 2 of Exhibit 3 will be larger and will occur sooner.

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FEDERAL POWER COMMISSION

Docket No. AR69-1

AREA RATE PROCEEDING
(SOUTHERN LOUISIANA) (PHASE I)

THE PEOPLES GAS LIGHT AND COKE COMPANY
NORTH SHORE GAS COMPANY

(Of the United Distribution Companies Intervenors)

DIRECT TESTIMONY OF JOSEPH P. THOMAS

Q. Please state your name, address and present employment.

A. My name is Joseph P. Thomas. I reside at 9859 South Bell Avenue, Chicago, Illinois. I am Vice President and Controller of The Peoples Gas Light and Coke Company, to which I shall hereafter refer as "Peoples Gas", and of North Shore Gas Company. I have been employed by Peoples Gas since October 17, 1941.

Q. Please outline briefly your educational background and business experience.

A. I attended DePaul University and received a degree of Bachelor of Science in 1949; later I attended Northwestern University and in 1956 received a degree of Master of Business Administration. I was employed by Peoples Gas in 1941. Prior to 1950, my work was principally in the General Accounting Department. From 1950 to October 1958, I was engaged in the Regulatory and Statistical Accounting Department.

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From October 1958 to July 1959, I was an Administrative Assistant in the Office of the Vice President and

Comptroller. From July 1959 to March 1, 1961, I was Manager of the Rates and Markets Department. From March 1, 1961 to April 1, 1963, I was Manager, Staff Administration, coordinating the activities of the Budget, Rates and Markets and Regulatory and Statistical Accounting Departments. From April 1, 1963 to April 2, 1964, I was Assistant to the Controller. From April 2, 1964 to April 1, 1965, I was Assistant Controller. From April 1, 1965 to October 1, 1966, I was Assistant Vice President and Assistant Controller. On October 1, 1966, I was elected to my present position.

Q. What are your responsibilities in your present position?

A. In general my responsibilities include the coordination and direction of accounting and financial control activities and policies. I am also responsible for rates and other matters subject to the jurisdiction of regulatory agencies, including the Illinois Commerce Commission and the Federal Power Commission. Market research and analysis are performed under my supervision and direction, and in this function I maintain close contact with our Sales Division.

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Q. Will you briefly describe the corporate status and operations of Peoples Gas?

A. Peoples Gas is a corporation organized and existing under the laws of the State of Illinois, with its principal office at 122 South Michigan Avenue, Chicago, Illinois, and is a public utility within the meaning of an Act of the State of Illinois entitled "An Act concerning public utilities" approved June 29, 1921, as amended, which I shall refer to as the "Public Utilities Act." Peoples Gas is engaged in the business of pur-

chasing, distributing and selling gas within the City of Chicago, and as an adjunct to its distribution facilities, has developed and operates an underground storage reservoir near Mahomet, Illinois.

Q. What is the corporate relationship between Peoples Gas and Peoples Gas Company?

A. Peoples Gas Company, which is a corporation organized and existing under the laws of the State of Illinois with its principal office at 122 South Michigan Avenue, Chicago, Illinois, has acquired all of the common capital stock of Peoples Gas. Peoples Gas Company has also acquired all of the common capital stock of North Shore Gas Company, to which I shall hereafter refer as "North Shore", and of Natural

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Gas Pipeline Company of America, to which I shall hereafter refer as "Natural."

Q. Please describe the corporate status and operations of North Shore?

A. North Shore is a corporation organized and existing under the laws of the State of Illinois, with its principal office at 3001 Grand Avenue, Waukegan, Illinois, and is a public utility within the meaning of the Public Utilities Act. North Shore is engaged in the business of purchasing, distributing and selling gas in a territory of approximately 275 square miles in northeastern Illinois. It serves 46 communities in Lake and Cook Counties, Illinois, which for the most part are considered to be Chicago suburban area.

Q. Please describe the market growth of Peoples Gas and North Shore.

A. In the five year period ending with 1969, total sales by Peoples Gas and North Shore increased by 32

per cent. The bulk of this increase was sales to customers with space heating. This type of sale increased 72 per cent.

Q. Please give an indication of how the space heating market has grown for Peoples Gas and North Shore.

A. Expressed in terms of new space heating business

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equivalent to single-family homes. Peoples Gas and North Shore have added in the last five fiscal years (ending Sept. 30) new heating business and I believe will add new heating business in the current fiscal year as follows:

1965	61,000	equivalents	
1966	63,000	"	
1967	65,000	"	
1968	65,000	"	
1969	74,000	"	
1970	83,000	"	(estimated)

The majority of these "equivalents" have been the result of conversions from another fuel to gas in existing buildings.

Q. Do you expect space heating attachments to continue at an increasing rate?

A. Yes, I do. This increasing rate is indicated by my previously stated estimate for 1970 which is based on experience of the first five months of this current fiscal year.

Q. Can you give any explanation for this increasing rate of new space heating business?

A. Yes I can. The recent growing concern over the problem of air pollution has had great impact upon the rate of attaching new gas space heating business. For instance, in the City of Chicago, a large con-

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version market exists for older apartment buildings which still burn coal or oil for space heating purposes. The amount of new gas space heating business from this sector of the market has been steadily increasing. Helping to influence many owners of buildings burning coal or oil to switch to gas heating plants are local ordinances which limit the future burning of the high sulfur coal and oil that is common in the Chicago fuel market.

Q. What is the nature of the local ordinance limitinf high sulfur fuels?

A. It will be unlawful to burn fuels with a sulfur content higher than that indicated in the following schedule in the City of Chicago:

2.5% beginning July 5, 1970
2.0% beginning July 5, 1972
1.5% beginning January 5, 1974

Q. Do you anticipate the air pollution problem to continue to influence your attachment of new gas space heating business?

A. Yes, until the time when the space heating market becomes heavily saturated with gas heating, the problem of air pollution will increase the demand for gas space heating. The present space heating saturation on a year round firm gas basis is 57%

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of the residential dwelling units and 34% of the nonresidential floor area.

In addition to its influence on the heating market, air pollution has also affected the market for conversions to

natural gas from other fuels for industrial processing and other large non-space heating loads. A number of the valley gas customers of Peoples Gas and North Shore have upgraded their lower-priced valley gas service to the higher priced year-round firm gas service. It is difficult to estimate a long-range picture of how much effect conversions of this type will have upon our gas supply situation because of their irregular occurence and variance as to size of load. However, if a large number of these conversions are made in the future, additional pressure will be put upon the need for natural gas.

Q. Is there a pending proceeding in Illinois concerning air pollution which could affect the demand for natural gas in your market area in the future?

A. Yes. On November 11, 1969, the Illinois Commerce Commission by an Investigative Order commenced a proceeding entitled *Illinois Commerce Commission* v. *Commonwealth Edison Company, et al.*, (Docket No.

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55321) to consider the problem of air pollution as it is caused by the process of the generation of electric energy. The Illinois Commission joined all of the major Illinois electric distribution companies as respondents for the purpose of presenting evidence to explain "in detail the nature of their generating processes, including fuels used, the sources and kind of pollutants, the efforts heretofore made, and planned in the future by said companies to abate the pollution." The major Illinois gas distribution companies were joined in this proceeding to present evidence "on the question of natural gas reserves and immediate supplies, on the cost factors involved, together with competing demands on available supplies, and all other matters pertinent to the question

of natural gas as a fuel for the generation of electric energy."

The Attorney General of Illinois has intervened in this Illinois proceeding, expressing his concern in this area, as have several public interest groups. The hearings are currently in progress.

There are substantial public pressures for the

reduction or abatement of air pollution by the substitution of natural gas for other fossil fuels and because of these reasons I expect an increased demand for natural gas for electric generating purposes and other large volume uses in our market area.

Q. What is the current supply situation of Peoples Gas and North Shore?

A. Natural is the major pipeline supplier of Peoples Gas and North Shore, and is currently obligated to deliver to us 1,000,000 Mcf at 1,000 Btu of flow gas on a daily basis. Peoples Gas also purchases flow gas from Midwestern Gas Transmission Company. The current daily contract quantity is for approximately 103,500 Mcf.

Natural also provides storage service to Peoples Gas and North Shore. The maximum daily contract withdrawal quantity amounts to 540,442 Mcf. In addition to the storage quantities available from Natural, Peoples Gas operates its Mahomet Storage Project which currently has a withdrawal capability of 250,000 Mcf per day for approximately 25 days per year available to Peoples Gas and North Shore.

Both companies also maintain liquefied petroleum gas facilities. The use of these facilities is restricted and considered to be for extreme peak day use because of the limited quantity in storage

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and the difficulty of replenishing supplies for such storage facilities during the peak season.

Q. Have Peoples Gas and North Shore contracted for any additional supplies of gas which is not yet being received?

A. Yes, we have entered into precedent agreements with Natural for additional quantities of gas to become available late in 1970, or in other words, available for the 1970-71 heating season.

In total Peoples Gas and North Shore have contracted for an additional 81,486 Mcf of flow gas; 40,397 Mcf of storage service under Natural's Rate Schedule S-1 to be provided through Natural's storage facilities; and 28,514 Mcf of storage service under Natural's Rate Schedule S-2 which is related to a storage service which Natural will obtain from Michigan Wisconsin Pipe Line Company. The flow gas quantities consist of 49,109 Mcf of Canadian gas and 32,377 Mcf of domestic gas and the Canadian portion is still subject to regulatory authority approval. The Federal Power Commission has approved the domestic flow gas and storage portions of Natural's applications to provide the additional quantities of gas.

Natural's Rate Schedule S-1 storage service cannot be utilized as a substitute for flow gas

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because of the operating and tariff provision limitation of this service to a thirty days availability. Peoples Gas normally requests all of the additional Rate Schedule S-1 storage capacity which can be allocated to it, in addition to the specific flow gas volume request which we make each year.

In addition to these quantities from Natural, it is hoped that the Mahomet Storage Project will provide another 50,000 Mcf of withdrawal capacity for Peoples and North Shore for the 1970-71 season. But this additional storage quantity is contingent on an analysis of the storage field's operation during the current heating season.

Peoples Gas and North Shore believe and are hopeful that the Rate Schedule S-2 storage service, which is a one hundred day storage service, their allocated part of Natural's Winter Service (Rate Schedule WS), and the additional storage quantity from Mahomet, along with their contracted for flow gas, will meet the requirements of their markets for the 1970-71 heating season.

Q. Do Peoples Gas and North Shore have prospects for additional supplies of gas beyond the 1970-71 season?

A. No, we do not. I have formally requested of various pipeline companies additional supplies of gas for the

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1971-72 heating season and beyond. However, I have not received any affirmative replies as of this date. Natural has advised us that they are making strenuous efforts to secure gas, but as yet have no "expansion quantities" contracted for 1971-72 or beyond, and Natural's personnel are not optimistic.

Q. What suppliers other than Natural have Peoples Gas and North Shore been in contact with for additional supplies of gas for the 1971-72 heating season and beyond?

A. Peoples Gas and North Shore gas have contacted each of the pipelines near their service area and are in the process of contacting other pipelines located at

greater distances from their market areas. We have been unable to obtain assurances for any additional gas.

Q. Which is your estimate of the additional gas supply which will be needed by Peoples Gas and North Shore for the 1971-72 heating season?

A. It is my opinion that beginning with the 1971-72 heating season, Peoples Gas and North Shore will need sources of supply equivalent to an additional daily flow gas supply in excess of 75,000 Mcf, if we are to serve all presently estimated load potential from the types of markets which we have been historically serving. If we were to attach new types of markets from which we have received some requests for gas, we would need even

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more.

Q. Have you given any consideration to alternative sources of supply?

A. Yes. As I have discussed previously, one source of supply alternative to our traditional sources is the importation of Canadian gas. Peoples Gas and North Shore have not directly attempted to obtain such supplies, but are due to receive Canadian gas through Natural in the previously indicated proposals pending before the Federal Power Commission and the Canadian National Energy Board, which supplies are needed for the 1970-71 winter. Additional supplies may become available from Canada but such supplies are, of course, always subject to the obtaining of regulatory approvals from agencies in both countries.

There are three other types of alternate supply which can be mentioned. First, there is liquefied petroleum gas which is presently used by Peoples Gas and North Shore on a restricted basis. Its cost is high, and as previously

discussed, storage requirements severely limit it to peak day use.

Another alternate source would be imported liquefied natural gas, or LNG. The use of imported LNG in this country has been very minimal and dates back to only one or two heating seasons. The delivery of imported

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LNG to the Chicago area could not be done economically under present technology because the present ocean-going LNG ships are too large to come through the St. Lawrence Seaway and because no LNG barges for use in the Mississippi River waterways have yet been constructed so that the economics and technology for that method of transport are as yet unknown. The possibilities of importing such higher price supplies by displacement or other means must certainly be considered if adequate domestic supplies are not available.

A third alternative to pipeline supply would be gasification of coal. However, this process is still in the research stage. A fairly advanced pilot plant for coal gasification has been built in Chicago, and it is hoped this will advance technology on this process. We are watching this Chicago pilot plant and other coal gasification experimental projects closely and will continue to do so. I believe that five to ten years would be the earliest time by which gas from a coal gasification plant would be available in commercial quantities in the Chicago area market.

Q. If supplies of gas other than those committed to Peoples Gas and North Shore do not become available, will any shortages be experienced?

A. Yes. On the basis of the anticipated growth of demand

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on our system for future years, we will experience shortages of gas supply to meet new demand beginning with the 1971-72 heating season.

Q. Do you foresee any immediate consequences to Peoples Gas and North Shore from the increasing space heating, industrial processing and other large non-space heating loads, and electric generation conversions to natural gas which you have described?

A. At the current time Peoples Gas and North Shore are planning to seek authority from the Illinois Commerce Commission to control or limit attachment of large volume customers switching from other fuels. The limiting provision would require one year advance notice for any request for year round firm gas service of over fifty thousand cubic feet per hour. The granting of such a request would also be subject to the availability of gas supply.

Q. Are there any limitation orders or notice requirements in effect as to Peoples Gas and North Shore at the present time?

A. No.

Q. Are there any limitation orders or notice requirements in effect in Illinois at the present time?

A. Not to my knowledge.

Q. Have limitation orders been in effect as to Peoples

[953]

Gas and North Shore in the past?

A. Yes. From July 19, 1946, until April 24, 1962, applications for space heating service from Peoples Gas were subject to limitation orders. During approximately

the same period of time limitation orders were also in effect for North Shore.

Q. Do you believe that it would be advantageous for the Peoples Gas and North Shore market area to pay higher prices in return for a reasonable assurance of increased domestic supplies of natural gas?

A. Because of the high cost and the as yet unresolved technological difficulties of supplyiny the Chicago area market with imported LNG or gas from coal gasification, and because of the high price and additional uncertainities involved in obtaining Canadian gas, it is my opinion that our market area has no choice: it must absorb some increase in the price of domestic gas if the market is to have an adequate supply of natural gas during the foreseeable future. Present indications are that domestic gas will not be made available to meet our needs at the present area prices. It is also my opinion that our Chicago area market can absorb some increase in price, and that consumers would prefer such increase to insufficient supplies. The pressure to control air pollution combined with the clean burning qualities of

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natural gas will undoubtedly offset some market disadvantage created by increased prices for gas. Accordingly, if there is a reasonable assurance that higher prices for domestic supplies in the producing area will result in increased supplies, it is the opinion of The Peoples Gas Light & Coke Company and North Shore Gas Company that such increase in price would be acceptable and desirable.

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AREA RATE PROCEEDINGS
(SOUTHERN LOUISIANA)

PREPARED DIRECT TESTIMONY OF SHERMAN H. CLARK

Q. Please state your name and address.

A. Sherman H. Clark, Menlo Park, California.

Q. Mr. Clark, by whom are you employed and what is your present position?

A. I am employed by Stanford Research Institute (SRI), Menlo Park, California, as a senior industrial economist. My present position is Director of Energy and Resources Economics.

Q. Describe the nature of your duties with Stanford Research Institute.

A. Broadly, we conduct economic research for government and industry throughout the Free World in many different fields. My own research studies have been primarily in energy and mineral resources, in all functions from exploration to exploitation, and from the various steps in manufacturing to the marketing of end products. I am therefore concerned with supply, demand, price, cost, feasibility, marketing, diversification, corporate strategy, and government policy.

Q. What is your educational and professional background?

A. I graduated with a B.S. in Engineering Science from Harvard College in 1945. I received a Master's Degree in Mechanical Engineering from Harvard in 1947. I spent an additional 2 years doing graduate work in engineering at Stanford University from 1950 to 1952.

Prepared Direct Testimony of Sherman H. Clark

I was Project Engineer at the Hanford Works of General Electric Company in Washington from 1947 to 1950. I joined Stanford Research Institute in 1952.

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For the past 17 years I have conducted studies for SRI in the United States, Canada, South America, Europe, the Middle East, and the Pacific Basin on diverse aspects of industrial activity, frequently in connection with the feasibility of new products, including projects involving crude oil, petroleum products, and natural gas pipelines.

Q. Have you presented evidence in proceedings before the Federal Power Commission?

A. Yes. I have testified in several major proceedings with respect to natural gas requirements and related matters.

Q. Please describe the SRI energy-related studies for which you have been responsible during the past 5 years.

A. Since 1965 I have either directed or prepared reports and studies relating to energy sources, markets, uses, and competition, including studies in the following general areas:

1. *Reports for Stanford Research Institute's Long Range Planning Service—*

   Interfuel Competition, Natural Gas in Great Britain, and World Energy. I have also directed the research on other reports including The Coal Industry, The U.S. Electric Power Industry, and Energy in Western Europe.

2. *Domestic Studies—*

   Markets for Western Coal and Markets for Petroleum Products in the West; An Analysis of the

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Prepared Direct Testimony of Sherman H. Clark

Factors Affecting the Outlook for Great Lakes Pipeline Company; U.S. Markets for Liquid

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Hydrocarbons Transported by Interprovincial Pipeline Company; Commercial Nuclear Power and Nuclear Fuel Requirements in the United States; An Economic Comparison of Nuclear and Conventional Fuel-Fired Power Plants in the U.S.; A Rate Analysis for a petroleum products pipeline; The Overall Significance of the U.S. Oil Import Control Program; corporate strategy studies for several independent oil companies; an antitrust study for an oil company; and analysis of by-product values for a shale oil deposit.

3. *Foreign Studies*—

A long range energy plan for a country in the Middle East; feasibility of natural gas service to Sweden; feasibility of a petroleum refinery in Bilbao (Spain); comparative feasibility of a petroleum refinery in Tarragona and Barcelona (Spain); feasibility of a petroleum refinery in Portugal, based on a competitive energy study; export markets for Australian steam coal; East-West trade in energy.

4. *Other Studies*—

Commercial Opportunities in the Nuclear Power Industry in the Free World. SRI is also conducting a comprehensive study on the feasibility of synthetic fuels production from coal, oil shale, and tar sands.

Q. What are the purposes of your testimony in this proceeding?

Prepared Direct Testimony of Sherman H. Clark

A. My basic purpose is to project the future requirements for natural gas produced from the Southern Louisiana area. To project these

requirements it is first necessary to project the demand for natural gas in the United States within the framework of the total thermal energy requirements and then estimate the portion of the total gas requirements reasonably attributed to the Southern Louisiana supply area. These studies are contained in my Exhibit No. 4 (SRI-1), which has been prepared under my direct supervision and is entitled "Requirements for Southern Louisiana Natural Gas Through 1980".

Q. Please describe the scope of your Exhibit.

A. I have subdivided the supporting data and computations in this study into four parts.

Part I of the study contains the basic data that, together with our economic analysis, underlie the demand estimates for natural gas for the United States and for the groups of states in each of the nine Census Regions. Demand for natural gas is presented in total and by its principal end use such as residential and commercial, and industrial. The data and the figures in Part I are constructed for a thirty (30) year period and provide annual figures for each year from 1950. In this manner both historical and projected demand for natural gas can be observed and compared. Also, the Census Region data can be compared from region to region by specific end use, as well as with the national results.

Part II provides the basis for the determination of the production required from the Southern Louisiana area.

Part III provides the data and materials on relative fuel use and prices of gas and competing fuels that have been used to assess

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the effect of potential future price changes on the demand for natural gas.

Part IV contains the Appendixes. Appendix A details the economic framework used in this study. Appendix B is a compilation of price data, by state, for some of the end uses for natural gas and other fuels, as well as the ratios of the prices of gas to the prices of other fuels. Appendix C presents the classifications of the individual fuels, end uses considered, and source notes. Appendix D shows fuel conversion and other conversion factors used in this study. Appendix E identifies the states included in the various Census Regions.

Q. Please briefly summarize your conclusions.

A. Our study shows a continuing increase in the demand for natural gas through 1980. We expect the demand to increase from 19.86 trillion cubic feet in 1968 to 27.8 trillion cubic feet in 1975 and to reach 34.5 trillion cubic feet by 1980. The year by year estimates for 1968 through 1980 are tabulated below:

Year	Total Demand (trillions of cubic feet per year)
1968	19.9
1969	20.9
1970	21.7
1971	22.9
1972	24.0

[962]

Year	Total Demand (trillions of cubic feet per year)
1973	25.1
1974	26.4
1975	27.8
1976	29.0
1977	30.3
1978	31.8
1979	33.2
1980	34.5

For the Southern Louisiana Area alone, the production requirements are expected to increase from 6 trillion cubic feet in 1968 to 9.5 trillion cubic feet in 1975 and to 11.5 trillion cubic feet by 1980. The year-by-year estimates for 1968 through 1980 are:

Year	Requirements for Southern Louisiana Natural Gas (trillions of cubic feet per year)
1968	6.01
1969	6.80
1970	7.60
1971	8.10
1972	8.44
1973	8.79
1974	9.14

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1975	9.50
1976	9.87
1977	10.26
1978	10.66
1979	11.07
1980	11.50

[963]

Prepared Direct Testimony of Sherman H. Clark

Q. In Part I of your study, you have analyzed the requirements for natural gas and competitive sources of fuel and energy. Please describe the economic framework for this analysis.

A. As used in this study, thermal energy requirements include all domestic, commercial, and industrial uses of fuel, including the fuel input to electric power plants. This definition excludes the use of fuel for transportation (except pipeline fuel). The definition also excludes the use of electricity in all applications, although the competition between gas and electricity in the domestic market is considered to assess more realistically the long term trends in gas demand in this application where electricity exerts powerful competition. In addition, the generation of electric power is also incorporated in my analysis to derive the fuel input requirements for steam electric plants.

Historical data for the period 1950 through 1968 were obtained and developed for the following items:

[964]

1. Each state (wherever possible) and the nine Census Regions of the United States, except that Alaska and Hawaii, normally in the Pacific Region, were not included. The Census Regions are described in Appendix E.

2. Each major end use: residential and commercial, steam-electric power plants, and all other industrial fuel demand.

3. Each fuel: natural gas, residual fuel oil, bituminous coal, and other fuels. Consumption of electricity for residential uses was also considered. In addition, data necessary to arrive at estimates

of net production of natural gas were also obtained. Projections for the years 1969 through 1980 inclusive were then made for each of the above classifications.

Q. What are the basis economic assumptions in this analysis?

A. The basic economic assumptions relating to the projections of demand are:

1. There wil be a moderately high level of economic activity: Gross National Product (GNP) and industrial production to increase at about 4.4 percent per year.

2. The international cold war climate will continue but there will be no war among the major powers.

3. There will be no radical advances in technology that will result in an abrupt change in the basic fuel consumption trends.

4. Adequate supplies of each fuel will be available to meet the projected requirements.

[965]

5. There will be no radical change in governmental policy that will further restrict the consumers' freedom of choice of the type of fuel to be consumed or that will change the relative economic attractiveness of each fuel.

6. Normal weather and watershed run-off conditions will prevail.

The economic parameters—GNP, personal income, and value added by manufacture—used in this

study and given in Appendix A were derived from the assumption of a moderately high level of economic activity. Business cycles were not considered—except that 1969 and 1970 are assumed to be years of low economic growth—because they will have no effect upon the long term trend of natural gas demand.

Q. In your projections of natural gas demand, what are your assumptions as to price and other factors influencing market acceptance?

A. I have assumed a continuation of past trends; i.e., essentially constant relative prices, continued overall preference for natural gas over other fuels, and gradually increasing preference for electricity over natural gas in the residential and commercial market.

Q. Please explain the basis for these assumptions.

A. The assumptions as to economic activity, absence of a major war, gradual advances in technology, normal weather conditions, and continuing government policies are the most realistic that can be made for the purpose of this study. As I will explain, however, governmental policy limiting sulfur content of fuels and permitting unlimited imports of residual fuel oil into PAD Districts II, III,

[966]

and IV might change the market shares. This is particularly significant for coal and oil, but potentially may affect the natural gas share as well.

The assumptions on adequate fuel supplies and constant relative price may be subject to some uncertainty. Adequacy of the supplies of coal, gas, and electric power is not entirely certain. Consequently, the projected re-

quirements for each fuel and energy source may not be met.

Q. What has been the trend in relative price and in the overall relative attractiveness of natural gas versus other fuels and electricity?

A. The recent experience has been heavily oriented to essentially constant relative price (i.e., the price of gas has maintained a constant relationship to the price of other fuels and electricity), but it is apparent from all the data that price is but one of many considerations in overall market acceptance. In terms of overall attractiveness, it is obvious that natural gas has continued to be the preferred fuel in most applications in most regions of the country. However, the overall market acceptance of electricity in the domestic and commercial market is gaining on natural gas.

Q. Does the assumption of constant relative prices imply that actual prices of each fuel and energy source will remain constant?

A. No. Although actual prices have been quite constant for the past 5 years, I expect most prices to increase for some time.

Q. Please explain SRI's estimating procedures.

A. The steps are as follows.

[967]

For estimates of residential and commercial consumption:

1. Summarize total thermal energy consumption in each state and Census Region for 1950 through 1968.

2. Adjust the heating portion of this consumption to normal weather conditions by using the degree day factors data given in Appendix D.

3. Correlate total fuel use with appropriate economic indicators (such as population and income) by using both statistical and graphical techniques. Develop projections on the basis of statistical tests and judgment.

4. Develop price series and calculate historical relationships in prices of gas and other fuels.

5. Analyze the competition between gas and electricity.

6. Calculate and estimate the projected gas share of the market based on statistical correlations of historical gas share, competitive fuel price relationships, and income.

For estimates of steam-electric consumption:

1. Develop historical kilowatt-hours (kWh) of thermal and hydro production of electric energy for 1950 through 1968.

2. Project total electric energy production by correlating with appropriate economic indicators (population and income) and by using both graphical and mathematical techniques.

3. Subtract estimates of hydroelectric and nuclear power production. The balance is the actual and projected steam-electric power production.

[968]

4. Develop historical fuel input to steam-electric power plants and calculate the heat rate (i.e., British thermal units (Btu)/kWh). Project the heat rate on the basis of past trends plus power industry outlook for heat rate.

5. Project fuel requirements of steam-electric plants by applying projected heat rate to projected steam-electric plant power production.

6. Project the gas share of the total fuel market.

For estimates of other industrial consumption:

1. Develop historical total fuel consumption by each state and Census Region.

2. Correlate with value added by manufacture and analysis of the direction and magnitude of use for each major subcategory.

3. Project the share of the market for gas.

For estimates of consumption by other categories:

1. Assume the small use of carbon black will continue.

2. Base the consumption by other outlets on trend and analysis of the direction and magniture of use for each major subcategory.

3. Assume that losses and wasted will decline gradually as in the past.

4. Base consumption of net imports on previous studies by SRI of import potentials.

Q. Has this method of analysis been used by SRI in past studies?

A. Yes, we have conducted many studies of this nature in the past and have used the same estimating procedures. Of course, continual

improvements have been made possible by the acquisition of additional data and by the increased practical knowl-

edge of energy economics. In addition, as increased effort is devoted to the development of alternative or supplementary sources of natural gas such as coal gasification and importation of LNG, we have taken into account the contribution that these sources may make to the satisfaction of market requirements for gas.

Q. How were the data collected for your presentation in this proceeding?

A. The great majority of the annual data, which were generally available by state, were developed from published sources including government and nongovernment publications such as U.S. Bureau of Mines, U.S. Department of Commerce, American Gas Association, National Coal Association, Edison Electric Institute, and various trade publications. Regional data for a few of the minor fuels (petroleum coke, for example) are not available; hence, it was necessary to estimate consumption of these fuels.

Appendix C contains source notes for each class of fuel used in this study.

Q. How did you convert data from the various sources into a single unit of measurement?

A. Individual fuels are reported in different units—tons, barrels, gallons, or cubic feet. It was necessary to convert all fuels into a common basis of measurement. In this study the Btu was used. The Btu used for each fuel is provided in Appendix D.

[970]

Q. Please explain why you consider gas requirements within the framework of total thermal fuel consumption and why do you consider competitive sources of fuel and energy.

A. This method provides an overall perspective of the energy market and the relative share of each fuel. Moreover, the effect of other price assumptions on the demand for natural gas can be ascertained.

Q. Why do you assess the requirements for natural gas by region and by end use?

A. Again, this information is useful for many purposes including revenue calculations and consideration of the effects of changes in the relative prices. Detailed analysis permits greater testing of the end results and thereby allows increased confidence in the projections. The regions vary enormously in their use of thermal fuels; e.g., natural gas serves virtually the entire thermal fuel market in the West South Central States and as little as 12 percent of the market in New England, with the average for the country approaching 50 percent. The gas market share in each application varies too, particularly by end use by region.

Q. Please discuss the national results of your study.

A. Figures I-1 and I-2 of Part I of my exhibit provide summaries of the historical and projected quantities of natural gas by end use and Census Region, and thermal energy demand, both nationally and by Census Region. Figures I-5 through I-8 show the energy demand by type of fuel in each major category such as residential and commercial, and industrial. Figure I-6 shows the production of electric energy.

[971]

Figure I-3 shows that natural gas is projected to increase its share of the total thermal fuel market from 45 percent in 1968 to 52 percent by 1980 and that the use of gas is expected to be over 50 percent greater than

the use of coal, and well over twice as great as the use of oil in thermal fuel application by 1980.

In the residential and commercial market, natural gas is also the dominant fuel, serving 56 percent of the market in 1980 (Figure I-5). Gas is now used twice as much as oil, whose use is expected to remain relatively static. Gas use is projected to increase at 4.3 percent per year in this market, but the use of electric heating is projected to increase significantly faster at 13 percent per year. Notwithstanding this tremendous increase in electric heating, in 1980 gas is expected to have increased its percentage of the total market to 59 percent.

The results of our study of conventional fuel consumption by power plants are shown in Figure I-7. As can be seen, thermal fuel consumption will be slowed considerably. This reduction in growth rate is caused by the rapid entry of nuclear power (see Figure I-6). Coal is still the dominant fuel and is expected to account for the major portion of the requirements, with the gas share holding at about its present level of 30 percent.

Lastly, the demand for industrial fuel has been increasing during the past 5 years in contrast to the rather static demand of the 1950s. Continued growth at about 2.6 percent per year is expected. In this application, gas is experiencing extremely good acceptance and now

[972]

accounts for about 55 percent of the total requirements. Our analysis projects that gas will account for almost all of the increase in requirements, with the growth rate of gas consumption for industrial use at 4.6 percent per year.

Q. Have air pollution control regulations affected your projections for the various fuels?

A. Yes. During the period of our study, air pollution control will definitely affect fuel consumption in the Pacific and Middle Atlantic regions where stringent rules now cover a large part of those regions, and gas requirements are thereby increased. Although similar rules are likely to be applied throughout the country, administrative lags will probably delay their effectiveness during part of the decade. Consequently, we did not significantly alter our projections for the other regions.

Q. In addition to major uses of natural gas that you have described, what other uses of natural gas are included in your estimate of total demand?

A. The data for Figure I-1 separate industrial demand into petroleum refinery consumption and all other. In addition, historical data are provided for the following subcategories, with projections for broader categories, as follows:

Noncompetitive gas demand—

Plant fuel
Pumping and drilling
Pipeline fuel

[973]

Nonenergy demand—

Carbon black
Other petrochemicals

Other demand—

Extraction losses
Net additions to storage

Transmission losses and unaccounted for.

Q. Please indicate the importance of these outlets and describe their trends.

A. In 1950 these uses totalled 2 trillion cubic feet or about a third of total demand. That share dropped rapidly in the 1950s, but in recent years their share has been declining slowly, reaching 20 percent in 1968 (3.8 trillion cubic feet). The share is projected at 18 percent in 1975, or 4.9 trillion cubic feet and 17 percent in 1980 (6 trillion cubic feet).

The most important of these other uses is the non-competitive energy demand, which includes plant fuel, pumping and drilling, and pipeline fuel, totaling 1.8 trillion cubic feet in 1968. The growth in this category should continue in line with the growth in total gas demand.

Extraction losses and net additions to storage total a little under 1 trillion cubic feet and will remain relatively static. Similarly, transmission losses and gas unaccounted for should remain relatively constant, at about 300 billion cubic feet per year.

The most rapid growth in these other applications is in the petrochemicals. With carbon black included, petrochemicals account for over 700 billion cubic feet and are expected to reach 1.4 trillion cubic feet by 1980. Natural gas is not nearly so important a petrochemical feedstock as natural gas liquids. Thus, natural gas as a petrochemical feedstock is not growing so rapidly as the total feedstock demand. Although petrochemical feedstocks will increase 8.8 percent each year, natural gas as a feedstock has a projected growth of only 5.5 percent per year.

Q. As you previously testified, the results of the Stanford Research Institute Study have also been pro-

vided for each of the nine Census Regions. Did you find any significant trends in any of these regions?

A. As is apparent from Figure I-2, all of the regions are expected to participate in the growth of natural gas demand and to grow at a fairly consistent rate. The most significant fact in the projections is that, for every region and for most of the end uses, the past trends are expected to continue fairly uniformly. But some regions are far more important than others in terms of absolute consumption. In particular, the West South Central, East North Central, and Pacific regions account for 17.8 trillion cubic feet of the total gas demand in 1975 and 22.3 trillion cubic feet by 1980.

The principal exception to the relatively steady trends is the fuel input to power plants, which will be affected by the rather massive introduction of nucelar plants in the 1970s.

[975]

Nuclear power will experience the major increase and will have a substantial effect on the future growth of conventional thermal power generation, particularly between now and 1975, as the enormous nuclear capacity ordered in the past few years comes into service. My estimate of nuclear power generation in 1980 is based on an estimated installed nuclear capacity of 126,000 MW. This is the maximum capacity (actually somewhat above the maximum) that can be operated at base load conditions, i.e., at about an 80-percent load factor.

Q. Please summarize the outlook for each fuel and for total thermal fuel consumption.

A. As testified, the historical and projected trends are shown in Figure I-3, for coal, oil, gas, and miscellaneous minor fuels in the residential and commercial,

industrial, and power plant fuel markets. However, Figure I-3 does not include the other applications for gas and does not include the Btu equivalent of nuclear and hydroelectric power generation.

Taking all thermal fuel applications into account and all fuels or competitive energy sources, the actual 1968 and the estimated 1975 and 1980 magnitudes are summarized below:

	1968	1975	1980	Annual Increase, 1969-1980 (percent)
	(Quadrillions of Btu)			
Coal	11.8	12.9	15.5	2.2%
Oil	7.2	8.1	8.7	1.5

[976]

Gas	21.1	29.3	36.2	4.6
Other fuels	1.6	2.4	3.5	6.7
Nuclear	0.1	4.5	9.0	30+
Hydro	2.2	2.6	2.7	1.8
Total	44.0	59.8	75.6	4.6%

The overall growth rate is of substantial significance for several reasons. First, the growth rate for thermal fuels demand is expected to be slightly greater than the growth rate for the economy as a whole. In the 1950s, energy demand grew much less rapidly than the economy. Second, the projected growth rate for the economy is higher than the average growth rate for the 1950 through 1968 period, and the projected growth rate for thermal fuel demand is also higher than our historical experience. Fuel demand appears to be accelerating, and if this continues, the growth rate for the last 5 years of the projection period may have to be increased further than it has been in the study.

Natural gas is projected at the same growth rate as total thermal fuel requirements, or 4.6 percent per year, even though electric heating is expected to grow quite rapidly and nuclear power generation extremely rapidly. Both coal and oil are expected to experience a low rate of growth. Air pollution control rules and changes in the oil import regulations that relate to residual fuel oil in PAD Districts II,

[977]

III, and IV can affect the growth rates for coal and oil as well as for gas. Both influences would unfavorably affect coal but would increase the growth rate for oil and gas.

Q. You have indicated that strictly enforced national air pollution contorls could affect the market shares of the individual fuels during the decade. Would you explain the effect?

A. Quantitatively, it is not possible to measure the effects at this time. But as an example of the potential severity of the impact, there is still no practicable solution by which most of the domestic coal can meet the low sulfur requirements. Therefore, most of the 12-trillion-cubic-foot equivalent of coal consumption is exposed to the impact of air pollution controls. Some loss of coal production is likely to be offset by coal gasification, which we treat as a portion of gas requirements. It is fairly certain, however, that the cost of industrial and power plant fuel will increase because of air pollution regulations, and this factor might well increase the use of gas.

Future enforcement of air pollution control certainly alters the comparative economics of the fuels, with gas most favorably affected, low sulfur fuel oil less favor-

ably affected, and coal adversely affected. But the extent of the shift away from coal and the portion that will shift to gas rather than to low sulfur fuel oil is impossible to measure at this time.

Q. Have you separately projected the intrastate market in Louisiana?

A. Yes. In addition to the West South Central states, which together account for 9.18 trillion cubic feet of the demand in 1975 and

[978]

11.6 trillion in 1980 and thus provide a very substantial intrastate market, I considered the intrastate market in Louisiana alone. The Louisiana data appear under the tab, "West South Central," in Figure I-45 and in the tubular information immediately following it. Louisiana consumed approximately 1.7 trillion cubic feet of intrastate production in 1968.

Q. Did you study the potential growth in the Louisiana intrastate market?

A. Yes. In addition to statistical information available to us, the SRI research team made field surveys that included discussions with personnel of the industrial development agency of the state and the public utilities commission of the state, as well as with personnel of electric utilities in Louisiana and of an industrial gas pipeline. These discussions provided information on the economic growth anticipated for Louisiana as well as on potential gas usage.

Q. Has the economic growth in Louisiana paralleled the economic growth of other areas?

A. Louisiana has not had nearly so dynamic an economy as the nation has enjoyed. There is no indica-

tion that this lesser growth experience for Louisiana will be reversed in the decade ahead.

Q. What is the trend in the growth of demand for natural gas in Louisiana?

A. From 1955 through 1965 total natural gas consumption grew slowly compared with the nation as a whole. But since 1965 gas consumption spiraled, increasing almost 50 percent in the last three years.

Q. Please describe the relative importance of the various gas applications in Louisiana.

[979]

A. The tabulation below provides the percentage of each end use in relation to total demand historically and as projected.

End Use	Percent			
	1950	1968	1975	1980
Residential and commercial	7.4	6.5	5.8	5.3
Petroleum refineries	15.8	8.0	7.5	7.0
Other industrial	26.9	35.8	32.8	28.3
Steam electric	12.7	14.9	21.7	27.8
Noncompetitive energy	31.2	15.9	14.1	13.3
Nonenergy	5.2	8.8	11.3	11.8
Other uses	0.8	10.1	6.8	6.5
Total	100.0	100.0	100.0	100.0

Industrial use is by far the most important, accounting for about 750 billion cubic feet or 44 percent of the total gas requirements in 1968. Residential and commercial use is only 5 to 6 percent of the total, and as such is relatively unimportant. Its growth rate is slow and should remain so primarily because overall population growth is low and is slowing. Furthermore, elec-

tric heat is increasing at 14 percent per year and this is also affecting residential and commercial gas growth.

Although gas used as power plant fuel has shown steady growth, it accounted for only 15 percent of the total requirements in 1968. On the other hand, industrial and petrochemical applications continue to increase and will constitute the major use of gas in the state during the next ten years.

[980]

Q. What is the overall outlook for intrastate gas demand?

A. I expect natural gas to continue to meet virtually all the increase in thermal energy requirements in Louisiana during the next 10 years. Gas demand will increase to 2.2 trillion cubic feet in 1975 and to 2.6 trillion by 1980. This is a growth rate of 3.4 percent between 1968 and 1980, or below the 4.6 percent for the nation.

Q. Is there any particular factor that is responsible for this level of increase in Louisiana's intrastate gas requirements?

A. I am anticipating that the North Shore oil developments will change the location of new petroleum-refining capacity from the Gulf to the East Coast and the upper Midwest. I therefore expect little growth in gas requirements for refineries and less than historic growth for petrochemical plants. Our field survey supports such a slower growth rate in petrochemical plants. This projection, together with low level of anticipated economic activity, supports lower percentage growth rate. But in absolute terms it represents a large requirement.

Q. Do you think the projected growth for Louisiana will be further dampened by higher gas prices at the well head?

A. No, I do not think the growth will be affected materially even by a substantial price increase. Displacement of gas by another fuel would now require a low sulfur fuel, and the present price for low sulfur fuel oil, low sulfur coal, or nuclear power presently ranges from 30 to 35 cents per million Btu, which is 50 percent to 75 percent higher than the present gas prices of from 20 to 21 cents per million Btu for power plant use.

[981]

Although it is possible that an appreciably higher local gas price could discourage the location of industry in Louisiana, which is extremely hard to evaluate, I do not think the effect will be any greater than I have assumed for the increase being anticipated within the state.

Q. Turning now to Part II of your exhibit, will you describe the share of national requirements to be satisfied from the Southern Louisiana area?

A. Southern Louisiana has been providing an increasing share of the nation's gas requirements since 1956 when net production was 1.4 trillion cubic feet. By 1968 net production had risen to 6 trillion cubic feet, and it is estimated to reach 7.6 trillion cubic feet by 1970. By the end of 1970, therefore, Southern Louisiana will be supplying 34.4 percent of the national demand and just over 50 percent of the increases in demand. Its position as a vital natural gas supply source cannot be seriously questioned, and substantial additional gas production must be forthcoming from this producing area if it is expected to continue to supply 34 to 35 percent of the nation's total requirements in the years following 1970.

[981]

Prepared Direct Testimony of Sherman H. Clark

Q. Does production from Southern Louisiana serve all market areas in the country?

A. No. The Pacific, Mountain, and West North Central areas do not receive gas from Southern Louisiana. However, Southern Louisiana does supply gas to all states in the other six Census Regions.

[982]

Q. What portion of the gas requirements for those six Census Regions is supplied with gas produced in Southern Louisiana?

A. Table II-2 of my exhibit contains data relating to Southern Louisiana's production and the requirements in the six Census Regions that receive portions of their supply from Southern Louisiana. In 1968 production from Southern Louisiana provided more than 40 percent of the requirements for those regions. A very high proportion of the requirements of Louisiana is met by Southern Louisiana production. Northern Louisiana production has been meeting a rapidly declining share of the requirements in Louisiana; its share is now down to less than 25 percent, and the share will continue to decline rapidly. In the other states within the six Census Regions, the proportions vary, but in most states Southern Louisiana supplies at least one-third of the requirements and in some states it provides as much as one-half of the requirements. Southern Louisiana is the major source of supply for the Middle Atlantic states.

Q. Has Southern Louisiana been increasing its market share of total gas requirements in the United States?

A. Yes. Between 1956 and 1968 total United States demand increased from 10.9 trillion cubic feet to 20.4

trillion cubic feet, but Southern Louisiana net production increased from 1.4 trillion cubic feet to 6.0 trillion cubic feet. The percentage of total United States requirements and also of the six Census Region requirements supplied from Southern Louisiana is indicated on Table II-2. The increase in percentage of gas requirements supplied by Southern Louisiana

[983]

reflects a disproportionately rapid increase in net production from Southern Louisiana compared with other producing areas. With the exception of New Mexico, the other major producing regions have either merely maintained their share or declined in market share over the past two or three decades. Thus, the performance of Southern Louisiana is attributable not only to its large increase in net production but also to the future of other producing regions to attain a parallel increase in their net production.

Q. Do you anticipate that the proportion of the country's gas requirements to be supplied from Southern Louisiana will be as great in the future as it has in the past?

A. Southern Louisiana provided 29.4 percent of the country's gas requirements in 1968, and in 1969 it appears that this producing area provided 31.4 percent of the total requirements. Although there may be a similar increase in market share during 1970, it is unrealistic to expect this trend to continue. If we assume that the future natural gas requirements that we have projected are actually met, other producing areas, as well as imports and supplemental sources, must be counted on to supply more gas than they have supplied during

the past few years. When a relatively new major supply source experiences the type of growth that has occurred in Southern Louisiana, its gain in market share has always leveled off even though net production continues to increase. For example, New Mexico experienced a rather rapid increase in market share until 1956, when its production leveled off. If New Mexico had continued its increase during the

[984]

past 12 years, its share would have been 50 percent higher than it actually achieved.

For all of these reasons, we have projected Southern Louisiana's historic growth rate through 1971 and then have projected future increases at that level. On this basis Southern Louisiana's increase in net production would still continue to meet its market share, rising from an estimated 6.8 trilion cubic feet for 1969 to 9.5 trillion cubic feet in 1975 and to 11.5 trillion cubic feet in 1980.

Q. You stated that, with the leveling off of Southern Louisiana's market share, imports of natural gas and supplemental sources would be needed to meet the projected gas requirements of the country. Is there any evidence that those sources can provide substantially increased supplies?

A. Yes, there are. The data for Figure I-1 of my exhibit set forth the gross and net imports of natural gas and indicate a sharply rising trend of supply from sources north of the border. At present, imports from Canada are rapidly increasing their market shares, and this trend will undoubtedly continue for a considerable period into the future. Exploitation of gas from the North Slope, including both Alaska and Canada, will

certainly be required even though these sources imply considerably higher delivered prices for gas.

Q. What is the likely timing of the entry of liquid methane, and in what volume?

[985]

A. The earliest possible entry is between 1973 and 1975, although I would anticipate sufficient slippage in the schedule might delay initial entry to 1974 and possibly 1975 (for the first full year of operation).

Presently, several major LNG projects are planned and scheduled to serve Eastern Seaboard markets. Under all of these existing projects, approximately 1 trillion cubic feet would be imported into the United States by 1975. If all of these projects are completed as proposed, imported LNG would be barely sufficient to meet the estimated increase in demand for New England and Middle Atlantic states only, which has been estimated at about 1.2 trillion cubic feet from 1968 to 1980 (Figure I-2).

However, the delivery schedules for these LNG projects may encounter regulatory delays or other problems which sometimes affect large new projects. Maintaining construction schedules for ships and facilities may be difficult when the starting date of construction cannot be guaranteed. Finally, start-up problems have been encountered on some liquid methane facilities and, considering the size of the facilities being proposed, this problem could also affect the proposed facilities.

Q. What is the anticipated price for liquid methane and how will it compare with pipeline-source gas?

A. The published announcement on Algerian-source gas indicated that the dockside price was expected to be 50 to 55 cents per Mcf.

I expect the actual city gate price to be in the range of 60 to 70 cents per Mcf for three principal reasons:

1. Inflation may well force the dockside price up.

2. From dockside to city gate can add 5 to 10 cents per Mcf.

3. Storage should also be added to the costs because the distribution companies do not operate at a 100-percent load factor.

In the Middle Atlantic region, the city gate price averages about 45 cents per Mcf; liquid methane, on the most comparable basis, will likely be roughly 20 cents per Mcf higher than the present average.

Q. What is the status of coal gasification?

A. A modest amount of research has been conducted on coal gasification. Coal gasification is technically feasible (although there are still technical problems), and unit costs have been reduced significantly. The major question, of course, is the specific level of unit costs likely to be achieved. Stanford Research Institute's current studies on coal gasification indicate that high Btu gas could be produced for about 50 cents per Mcf, but estimating construction costs applicable to any new facility over the next 5 to 10 years is difficult and creates some uncertainty; this is particularly true for "first generation" plants. The first plant or plants constructed will likely have unit costs higher than 50 cents per Mcf. These costs, incidentally, are applicable to midwest markets in which the present city gate price is 40 cents per Mcf or less.

[987]

Q. Are all the technical problems associated with coal gasification solved?

A. No. Coal gasification processes that eliminate most of the char and by-product production, which is essential if the industry is to achieve any large scale of total output, still have some technical problems. Two pilot plants are presently under construction, and operation of these plants will greatly contribute to the solution of the technical problems.

Q. What do you expect for the production of synthetic gas in 1975 and 1980?

A. It is barely possible that there wil be some production in 1975—if a company is willing to risk construction prior to operation of the pilot plants over a sufficient length of time to be confident about design considerations, solution of technical problems, and cost. I think it is more reasonable to expect commercial operation to begin in 1976 to 1978, with plants designed for a total output of 0.2 to 0.4 trillion cubic feet. The outside limit in 1980 is 1.0 trillion cubic feet, but my best estimate would be 0.7 trillion cubic feet. But the subsequent growth in the 1980s and beyond could be very substantial.

Q. Are air pollution control considerations likely to deter construction of coal gasification plants?

A. I do not think so, because the processes are designed to remove the sulfur in the coal for sale as a byproduct.

[988]

Q. Please summarize your estimates of the most probable level of supply of gas from all sources other than natural gas fields in the 48 continguous states.

[988]

Prepared Direct Testimony of Sherman H. Clark

A. Natural gas imports from Canada, Mexico and the North Slope totaled 0.6 trillion cubic feet annually in 1968 and should increase to 1.3 trillion cubic feet in 1975 and to about 2 trillion cubic feet annually in 1980. Presently scheduled LNG imports are 1 trillion cubic feet per year by 1975, and 1.3 trillion cubic feet by 1980. We do not see really significant coal gasification until 1980 when it is estimated to supply the equivalent of 0.7 trillion cubic feet annually. Between 1968 and 1980 I expect all these sources combined to contribute roughly 3.8 trillion cubic feet of additional supplies if the present LNG projects are completed as proposed. Our projected increase in demand in the same period is over 15 trillion cubic feet. In my judgment these sources other than the natural gas fields in the 48 states, although of great potential significance, cannot be exploited quickly enough and in large enough quantities to meet a major portion of the increase in gas requirements at any time in the 1970s; moreover, over the next 5 years these sources can supply a relatively minor portion of the increase in requirements.

Q. In developing your market projections what consideration did you give to the specific requirements of the major industrial users and to competitive factors?

[989]

A. Those factors affect the projected demand for gas and were taken into consideration in the preparation of our study. Part III provides data and testimony relating to (1) the competition between gas and other sources of fuel and energy, (2) the trends in which fuel and energy prices are likely to move in the next ten years, and (3) the effects on gas demand of a change in relative prices.

Q. Please describe the pattern of gas consumption by industry.

A. Table III-1 provides a breakdown of natural gas consumption for 10 different energy intensive industries, plus the total for all other industries combined. The petroleum refining industry consumes more natural gas than any other industry, but accounts for only 12 percent of the total industrial gas consumption. Moreover, all 10 of the fuel intensive industries combined account for only about half of the gas used by industry and this share is declining rapidly. By 1980 the nonfuel intensive industry will probably account for two-thirds to three-fourths of the industrial gas consumption. There is a rapid growth in the number of industries using natural gas, especially in the West South Central states.

Q. What is the significance of the increased use by industry?

A. As the use becomes more widespread, the averafe use per customer can be expected to decrease, the average unit price to increase, and the likelihood of and degree to which rapid shifts in fuel consumption by type of fuel will take place are diminished. In other words, with widespread use the industrial gas load tends to become more secure

and more important financially in that shifts to other fuels are minimized.

Q. Before we discuss the trends in gas consumption in the energy intensive industries, please summarize the outlook for gas in new power plant construction.

A. Of course, this is the most price-sensitive area when fuel choice and consumption are considered. Many steam-electric plants have multifuel facilities and can

easily change from one fuel to another. The primary test of a future continuation of the heavy gas usage in these plants can be assessed by studying the announced new additions to power plant capacity. We have compiled these additions for single fuels on Table III-3a and for multifuel capacity on Table III-3b for the years 1966-1973.

Summary results for the contiguous United States are:

	Thousands of MW	Percent of Total
Gas	5.3	8
Gas/other	20.9	32
Nongas	39.2	60
Total	65.4	100%

Forty percent of the capacity additions are being equipped to burn gas, and this is virtually the same percentage as for the most recent 7-year period, 1962 through 1968.

Hence, in the most price-conscious sector of all fuel users, it is clear that gas is holding its market share. On the other hand,

there is no indication that electric utilities are increasing the provision for the use of natural gas—which one might expect to be the case because of anticipated restrictions on air pollution. In fact, over half the total additions to capacity continue to be equipped to burn coal only.

Q. Are new steam-electric plant additions any more efficient from the standpoint of fuel usage?

A. No. The data in Tables III-3a and III-3b show that the most efficient plants added in the 1960s are not

appreciably more efficient than the most efficient plants built in earlier years. Steam-electric generation plants appear to be close to an efficiency plateau. Therefore, it appears that average heat rates are not likely to improve significantly by 1980 and thereby affect fuel consumption.

Q. Please describe the trends in fuel consumption in the iron and steel industry.

A. These trends are shown in Figures III-1 through III-3, by type of facility, and the totals for all facilities are shown in Figure III-4. The trends in iron and steel production are shown in Figure III-5.

The relative importance of that fuel consumption and natural gas consumption in the various categories of steel-making facilities is apparent from the tabulation below for the year 1968:

[992]

	Gas (trillion cubic feet equivalent)	Total Fuel (trillion cubic feet equivalent)	Gas as Percent of Total Fuel
Melting furnaces	0.1	0.2	50%
Other than melting and heating furnaces	0.1	0.3	33
Heating and annealing furnaces	0.3	0.5	60
Other facilities	0	1.9	0
Total	0.6	2.9	21%

The trends in the various applications are quite different. Total fuel consumption in the industry is increasing, although slowly, but fuel use in melting furnaces is declining, as is the use of natural gas, because of oxygen

injection and other technological developments that lower the specific fuel requirements.

Steel production is expected to increase at 2 to 3 percent per year. Total fuel consumption is expected to increase at roughly 1 percent annually and gas consumption at 2 percent annually. The growth is far from spectacular, and it will be difficult for the consumption of gas to grow much more rapidly because such a large percentage of the fuel used is own-fuel generated. The major competition for gas is fuel oil, most of which is probably low sulfur fuel oil. Since most of the steel companies are not located on the seaboard, it is difficult for low sulfur fuel oil to be available, and competitive with gas, at most steel facilities.

[993]

Q. How do the fuel requirements of petroleum refineries compare in magnitude with those of the steel industry?

A. They have about the same overall requirements, but the petroleum refineries rely on natural gas to a much greater extent. Refinery fuel requirements are also growing slightly more rapidly.

Q. What is the outlook for natural gas and total fuel requirements of refineries?

A. Total fuel requirements (Figures III-6 and III-7) should increase somewhat more rapidly than they have increased during the 1960s. But the increase in requirements for natural gas is now less certain. About 70 percent of the natural gas consumption by refineries is concentrated in the West South Central states, compared with 42 percent of the refinery capacity. If new refining capacity shifts to the East Coast and the upper Midwest as we expect, natural gas will not be used so

extensively. Another uncertainty is the extent to which refinery gas will be available. I have expected refinery gas consumption as fuel to decline gradually, but this has not yet been the case. Thus, although I expect the use of natural gas by refineries to increase, the estimate for 1980 is in the broad range of 1.3 to 2.5 trillion cubic feet but closer to the lower end of the range.

Q. What have been the trends in and what is the outlook for the cement industry and its use of fuel?

A. Figures III-8 through III-13 and Table III-2 provide the historical data on this industry. Total use of fuel is growing slowly and is

likely to continue to grow slowly during the decade. Total fuel consumption is only one-fifth to one-sixth as much as for the steel industry or petroleum refining and total fuel use is about 0.5 trillion cubic feet equivalent. Of this total, gas consumption accounted for 40 percent.

Gas consumption has been quite constant for the past 5 years, but coal consumption has climbed modestly and is now some 15 percent greater than the use of gas.

Interfuel competition is very intense in this application. However, rigid air pollution control rules will create severe problems for the cement industry in that it would have to pay more for its fuel, and in turn, the industry may shift to the use of natural gas to the maximum extent feasible.

Q. Please summarize your conclusions on the industrial sector.

A. This sector is a major outlet for natural gas, and the use of gas for industry can be expected to grow rapidly. In the fuel intensive industries, gas prices are generally the lowest and the interfuel competition is

the most intense. These industries will continue to use gas, but their share of the total industrial use of gas is expected to decline. However, the use of gas by smaller industries is expected to pick up any slack. As pointed out previously, in these industries price competition is not so intense and by 1980 the smaller industries should account for as much as 70 percent of the industrial consumption.

[995]

Rigid air pollution control rules, which are likely to spread throughout most of the country by 1980, will create problems for the industries that rely heavily on coal and also for those plants not on seaboard that presently use high sulfur fuel oil. Fuel costs for these plants can be expected to increase materially, and thus the potential for natural gas should be enhanced.

Q. What is the overview for the residential and commercial market during the period covered by your study?

A. It is extremely difficult to assess the gas and electric market shares in the residential and commercial market for two reasons. First, the electric consumption in this market that applies only to those uses that gas can also serve is not reported. Second, the units are different, and although we do make conversions into common units, the conversion for electricity is not nearly so precise as it is for the thermal fuels. For these reasons, I have assembled in Table III-5 the historical series on the annual sales of the principal gas and electric appliances: ranges, water heaters, and clothes dryers. These data provide a good indication of the trends in market share of these two important sources of energy.

Q. What conclusions can be drawn from the data in Table III-5?

A. The columns in Table III-5 labelled "Gas Sales as a Percent Total Sales" show fairly consistent results for all three appliances. Gas now accounts for 30 percent of the clothes dryer sales, 50 percent of the range sales, and 66 percent of the water heater sales, but in all three types of appliances, gas has been losing its market share.

[996]

For many years gas had been increasing its share of the clothes dryer market, but the gas share peaked in 1961 at 36 percent and has declined gradually in the subsequent years. The gas share of the water heater sales shows the same pattern, but the gas share of range sales declined since 1950.

Q. How large is the equivalent base use for electricity?

A. The basic data, by region, are given in Table III-6 (a and b). The total for cooking, water heating, and clothes drying has increased from 0.5 trillion cubic feet equivalent in 1960 to 0.8 trillion cubic feet equivalent in 1968—an average annual growth rate of 7 percent. As mentioned earlier, electric heating is growing at approximately 14 percent per year, and I am sure that electric air conditioning is also growing very rapidly, or in excess of 10 percent per year. For all residential and commercial applications that compete with gas, I am confident that the growth rate is in excess of 10 percent per year. The overall growth rate for gas in the residential and commercial market is projected at 4 or 5 percent per year.

Q. What are the comparative prices for gas and electricity?

A. Gas is generally less expensive in all applications. In terms of appliance prices (Table III-5) the gas appliances are roughly 10 percent lower in price than the electric appliances for 2 applications and are 10 percent more expensive for the third. There is no real relationship between the comparative appliance prices and the market share.

[997]

Q. What are your conclusions on the future of gas in the residential and commercial market?

A. Electricity is undoubtedly the major competition for gas and is gaining in market share, even though comparative prices tend to favor natural gas and have been fairly constant for the past few years. Despite the severe competition from electricity, I expect natural gas demand in residential and commercial markets to increase at a good rate—about the same rate of growth as the economy.

According to all available evidence, the consumer prices for gas and electricity have very little impact on their market share. Any change in the present relationship would probably have relatively little impact on the future trends. Significantly, electric rates are likely to reverse their long term trend and increase for an indefinite period. Hence, I do not anticipate that relative prices will change very much over the next 10 years.

Q. In the succeeding tables of Part III, you have presented data on the gas industry's load balancing and use of storage. How well is the gas industry maintaining its load balance?

A. As the data in Table III-7 indicate, the general load balance achieved by the use of storage injection and withdrawals continues to be extremely good and,

in fact, well above the ratios experienced in the 1950s. The data on the ratio of gas stored to heating sales also show that industry in the 1960s has continued to rely on storage to about the same degree (Table III-8).

[998]

Q. What is the trend in the use of storage?

A. The use of storage is continuing to increase at a rate close to 10 percent per year (see Tables III-9 and III-10 on gross withdrawals from storage and total underground storage), somewhat more rapidly than the increase in heating sales. Based on American Gas Association (AGA) data on planned construction expenditures, it appears that the gas industry will continue to expand storage capacity rapidly.

Q. What is the trend in interruptible sales?

A. Interruptible sales appear to be growing at roughly 7 percent per year. Indications on the trend are as follows:

	Trillions of Cubic Feet	Source of Estimate
1953	1.5	AGA
1961	2.6	SRI survey
1968	4.3	Requirements Committee

Q. What is the significance of the trends in load balancing, storage, and interruptible sales?

A. Achieving a high load factor is an important economic objective for the gas industry. Both storage and interruptible sales are used to achieve this objective, and the use of both is increasing. Although interruptible sales are generally low in price, these sales will continue to be an important tool in maintaining unit costs for all gas consumers.

[998]

Prepared Direct Testimony of Sherman H. Clark

Q. Have you compiled any data on the prices of gas and competitive fuels?

[999]

A. Yes. I have developed a time series, by state, for gas and oil prices for residential heating and gas, oil, and coal prices for the power plant market. These data are given in Appendix B.

Q. In the residential heating market what do the historical data on gas and oil prices indicate?

A. There are several important factors:

1. The price of gas for home heating is more than 40 percent below the price of distillate heating oil in over half of the states. Gas is 10 to 40 percent lower in price than oil in 15 states and is within 10 percent less in one state. Gas is more expensive than oil in only 3 states—New Hampshire, New Jersey and Oregon—but the differential is only from 2 to 5 percent or negligible.

2. Since 1964 the price of gas for heating has been generally stable to down; the price has increased modestly in some states. But the price of distillate heating oil has generally increased, particularly in 1967 through 1968, and increased further in 1969.

3. Both the long term (1953-68) and the short term (1964-68) trends in the relative price of gas and oil for home heating have been generally downward, again favoring gas.

Q. What is the significance of these observations from the standpoint of future price movements and potential effect on gas demand?

A. Basically, the above observations indicate that the assumption on future relative prices of gas and oil for

residential heating is not of critical importance. Gas should continue to capture virtually all of the increase in the heating market (except for electric heating),

[1,000]

even if the tresd in relative prices reverses—although I do not expect such a reversal.

As stated earlier, the major threat to the use of gas is the use of electricity. Relative price is a factor in that competition, but other factors appear to be more important, e.g., installed price of equipment or appliances, actual performance and impressions of performance in the minds of the consumer, and flexibility of combined services such as heating and air conditiong.

Q. You also have data in your exhibit on steam-electric fuel prices. What has been the trend in these prices?

A. There is no predominant pattern. In recent years heavy fuel oil prices have declined along the Eastern Seaboard, coal prices have increased in that region but declined in others, and gas prices have been relatively stable.

Q. What has been the trend in relative prices of gas and other fuels?

A. There has been some change, but in overall perspective the relative prices of gas and other fuels have been essentially constant in recent years. Although changes in relative prices might be the major influence on market shares, three important factors tend to impede a marked change in market shares:

1. Gas can increase in price relative to the price of other fuels by a substantial magnitude in the West South Central states, without creating a shift to other fuels.

2. Some utilities have had and will have to shift to more expensive fuels to meet air pollution control requirements. Air pollution

[1,001]

control rules may preserve a market for natural gas or even increase the market, even if gas were to increase in price relative to other fuels, despite the increase in price of coal and oil that could result from desulfurization.

3. Outside the West South Central states, gas used by power plants is generally interruptible. In some instances interruptible rates can be maintained even with rising costs to preserve the load-balancing benefits. In other words, power plant sales must be priced competitively.

Q. What do you think is the outlook for industrial fuel prices?

A. I have prepared several tables to answer this question. They are presented on an individual fuel basis: nuclear first, then coal, and finally I would like to discuss the outlook for fuel oil prices.

Q. How competitive is nuclear power and what is the outlook?

A. Large nuclear plants cost about $50 to $75/kW more than large fossil fired plants—depending upon the fossil fuel that is to be fired (Figure III-14). The unit costs increase for both nuclear and conventional plants with decreasing plant size. The differential between the two increases with decreasing plant size.

Construction costs have escalated dramatically since 1965 (Figure III-15) and are expected to continue to rise because of inflationary labor settlements and other

factors. This rise can be offset, in part, by building larger plants, but the effect of this is limited by the fact that it is doubtful that anything above 1500-MW units will become available for service much before 1980.

[1,002]

Both nuclear and conventional plants face additional capital cost elements. To meet thermal pollution limitations, for example, additional capital costs may be required:

	1975 ($/kW)	1980 ($/kW)
Nuclear plants	7	10
Conventional plants	5	7

Removing sulfur from the conventional fuels or sulfur compounds from the stack gases is a widely varying cost, and in some cases performance is still uncertain. From all the estimates I have studied, I think the average additional cost is likely to be the equivalent of an additional 5 cents per million Btu in cost of fuel.

For nuclear plants, the long term average fuel cycle costs are estimated at 2.0 mills per kWh. This figure anticipates that long term and continuing escalation will be to some degree offset by technological improvements. Operating and maintenance costs for nuclear plants and for fossil fuel plants are given in Table III-11.

Overall generating costs for nuclear units are given in Table III-12. For a plant to be put into service by the end of the 1970s, generating costs will be in excess of 6 mills per kWh. In the lower part of Table III-12, I have subtracted the capital charges plus the operating and maintenance costs for conventional plants from the

total generating costs of nuclear plants to determine the allowable cost of conventional fuel for the break-even point between conventional and

[1,003]

nuclear plants. For plants ordered now, the break-even price is close to 30 cents per million Btu. These estimates are more representative of coal-fired plants. The gas-fired plants in the West South Central states have lower capital costs and the break-even fuel price is as much as 5 cents per million Btu higher. By the mid to end-1970s, I expect the break-even price to be in excess of 30 cents per Mcf.

Q. What is the outlook for coal prices?

A. There have been modest price increases in the last year or two, and leaders of the coal industry state that prices will have to increase further.

Q. What do the trends in the cost components of the coal industry indicate?

A. Labor costs of coal mining per ton of coal (Figure III-16) declined steeply in the 1950s and to the middle 1960s. In the past four years there has been no further decline, and I anticipate sharply higher wage settlements that, with the higher costs associated with mine safety requirements, will result in a reversal of the long term trend.

The wholesale price indexes of mining machinery and equipment (Table III-13) also indicate rising prices for this equipment, and railroad freight rates for bituminous coal (Figure III-18) have reversed a 10-year trend, with some small increases since 1966. Further increases are probable. As a result, I expect delivered coal prices to increase during the 1970s by several cents per

million Btu. In addition, if air pollution control rules become widespread, which appears probable, we can expect higher prices (or the equivalent of higher prices by the removal of sulfur dioxide from stack gases) of an additional amount—for planning purposes, perhaps 5 cents per million Btu.

Q. What is the outlook for heavy fuel oil prices?

A. There is not likely to be any increase in heavy fuel oil prices in the near term. On the other hand, any change in the oil import control program designed to increase imports or even eliminate the controls would not lower the price of heavy fuel oil because it is already essentially exempt from the controls.

The effect of air pollution control rules creates uncertainty as to the price outlook over the long term. A substantial amount of low sulfur crude oil has been found in recent years that can supply substantial requirements for low sulfur fuel oil without causing higher costs. But if sulfur limitations become widespread throughout the Free World, then refineries will have to be modified to extract the sulfur from those crudes that contain sulfur—and this is the case for the bulk of the world's crude oil supply—and the price will then have to be adjusted upward by at least 5 cents per million Btu. However, this is not likely before the mid-1970s.

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* * * *

[1,152]

Testimony of Commission Staff Witness John J. McGrath

[1,152]

AREA RATE PROCEEDING
(SOUTHERN LOUISIANA)
Docket No. AR69-1

TESTIMONY OF COMMISSION STAFF WITNESS JOHN J. McGRATH

Q. Please state your name and address.

A. John J. McGrath. I reside in Silver Spring, Md.

Q. What is your position?

A. I am a Financial Analyst and Head of the Finance Section of the Federal Power Commission in the Division of Finance and Statistics, Office of Accounting and Finance.

Q. Please describe your qualifications and experience.

A. I was graduated from Columbus University, Washington, D. C., in 1940 with a degree of Bachelor of Commercial Science. From 1948 through 1951, I attended the School of Foreign Service at Georgetown University, Washington, D. C. I attended evening classes at both schools.

My employment with the Federal Power Commission commenced in December 1937. I have held various assignments, including four years of field work as an Examiner of Accounts in the Division of Accounts. I have been in the Finance Section since December 1950. From July 1943 to November 1945, I was in the military service. I am a member of the Washington Society of Investment Analysts.

[1,153]

Q. What are your duties with the Commission?

A. My duties are to supervise the review of rate increase applications filed by natural gas and electric

utilities for the purpose of analyzing the rate of return proposed and to review applications with respect to the financial feasibility of pipeline projects for which Certificates of Public Convenience and Necessity have been requested. They also include the review of financing plans submitted by applicants for a license under the Federal Power Act. It is also my duty to maintain data and prepare exhibits to be presented by me and other staff members in gas and electric rate cases and to present testimony at formal hearings.

Q. Have you previously testified before this Commission?

A. Yes, I have testified in the following cases before the Federal Power Commission: *G-5420, East Tennessee Natural Gas Co.; G-12391, Kansas-Nebraska Natural Gas Co., Inc.; G-5471, Alabama-Tennessee Natural Gas Co.; G-9262* and *RP61-3 et al., Houston Texas Gas & Oil Corp. et al.; RP63-1, United Gas Pipe Line Co.; RP61-19* and *RP62-7, Midwestern Gas Transmission Co.; E-7026, Wisconsin Michigan Power Co.; E-7038, Southwestern Public Service Co.; RP64-9, Cities Service Gas Co.; E-7114 et al., Delaware Power & Light Co.; RP65-4, East Tennessee Natural Gas Co.; RP66-12, Texas*

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Eastern Transmission Corp.; RP66-25, Alabama Tennessee Natural Gas Co.; RP67-21, Natural Gas Pipeline Company of America; RP68-1, Florida Gas Transmission Co.; RP68-2, East Tennessee Natural Gas Co.; RP69-13, Texas Eastern Transmission Corp.; RP69-14, Algonquin Gas Transmission Corp.; RP69-36, Natural Gas Pipeline Company of America; RP69-35, Panhandle Eastern Pipeline Co.; and *RP69-41, Texas Gas Transmission Corp.*

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Testimony of Commission Staff Witness John J. McGrath

In addition to the above cases, in which the subject matter was rate of return, I testified in the following certificate cases: *G-18338 et al., Coastal Transmission Corp. et al.* and *CP63-204 et al., Transwestern Pipeline Co. et al.* I also presented testimony on the cost of debt for Project Nos. 2243 and 2273, *Pacific Northwest Power Company* and *Washington Public Power Supply System.*

Q. What is your responsibility in this proceeding?

A. To determine a fair and reasonable rate of return which I consider currently applicable to remaining investments as well as future capital expenditures of oil and gas producers. I was also requested to supervise the updating of Exhibit Number 24, presented by Staff Witness Dr. Felix I. Shaffner in the Southern Louisiana Area Rate Proceeding, Docket No. AR61-2.

Q. Do you have two exhibits in connection with your testimony?

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A. Yes. One exhibit is entitled "Area Rate Proceeding, Docket No. AR69-1, Rate of Return Analysis, May 1970" and includes the notation "This exhibit corresponds to Exhibit No. 24 in AR61-2 (Southern Louisiana Area). It has been updated to include current information". It has been identificed as Exhibit No. 12 (JJM-1) in this proceeding. The other exhibit is entitled "Area Rate Proceeding, Docket No. AR69-1, Rate of Return Analysis, May 1970" and has been designated Exhibit No. 13 (JJM-2) in this proceeding.

Q. Were these exhibits prepared under your supervision and direction?

A. Yes.

Q. Please describe Exhibit, No. 12 (JJM-1).

A. The data in Exhibit 24 (by reference) as presented by Dr. Shaffner did not go beyond the year 1962.

The data set forth in Exhibit No. 12 (JJM-1) were updated through year 1968 using as far as possible the format of the original exhibit. Time did not allow for the preparation of updated charts.

Q. Please describe Exhibit No. 13 (JJM-2).

A. Exhibit No. 13 (JJM-2) was prepared to include current financial data for the companies which were made Respondents to this proceeding by Commission Orders, dated

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March 20, 1969 and December 15, 1969. Included also are data for all other producers who sold more than two million Mcf during 1968 and for whom financial data were available. Other general data is also included.

Q. How did you determine those companies whose sales exceeded two million Mcf during 1968?

A. By reference to the FPC publication *Sales by Producers of Natural Gas to Interstate Pipeline Companies—1968*, Table 1, pages 1 through 6. The publication contains the following comment:

> "The report does not identify production separately by producers. Sales by named producers may include gas purchased from other producers and thus the figures are not indicative of the volume of gas produced by the named producers. In assembling the data from the company reports, sales made by producers in association with other producers have been attributed to the producers 'first named' in the association."

Q. Please describe the schedule in your Exhibit No. 13 (JJM-2).

A. Page 1 is a copy of Table "D" from the FPC publication *Sales by Producers of Natural Gas to Interstate Pipeline Companies—1968*. This table shows the

sales by areas to natural gas pipelines by all producers as reported to the Commission by the pipeline companies. On pages 2

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and 3 I have shown the sales in Southern Louisiana Area and total United States sales by Respondents in this proceeding as they were reported to the Commission by natural gas pipeline companies on the purchase schedules of FPC Form No. 2. Pages 4 and 5 present the capitalization, revenues, and return on average common equity for the year 1968 of Respondents, per Order of March 20, 1969, for whom the information was available. Pages 6 and 7 contain the same date for Respondents, per Order of December 15, 1969. Page 8 shows the capitalization and earnings for 1968 for 17 natural gas pipeline companies who are. Respondents. These pipeline companies had no sales to report as producers. Of the 342 Respondents I was able to obtain financial information for 68 producing companies and 17 natural gas pipeline companies. Page 9 shows the same data as appears on the previous pages for producer Respondents for 1968, for producers who are not respondents in this proceeding, but, who did report sales of at least 2,000,000 Mcf. I have included data of the companies for whom it was available. Page 10 summarizes the total data from the preceding schedules, that is pages 4 through 9.

Page 11 shows the capitalization and return on average equity for the period 1961 through 1968 of

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companies used by The Chase Manhattan Bank in its annual analysis of the petroleum industry. In the fore-

word to its most recent analysis, dated June 1968, Chase states:

> "For many years The Chase Manhattan Bank has conducted a detailed study of the financial performance of a large number of petroleum companies. Because the combined operations of these companes constitute a major proportion of the worldwide activities of the petroleum industry, their combined financial performance provides a valuable basis for determining the probable experience of the over-all industry. . . .
>
> Over the years the number of companies in The Group has changed primarily as a result of mergers. But this does not affect to a significant degree comparisons of current data with those of prior years."

Twenty of the 28 companies in the latest Chase study are also included among the companies for whom I have furnished data. The following page, number 12, was prepared from information obtained in the Chase analysis. I have shown the capitalization and net income for 1967 and 1968 for the 28 companies divided between domestic and foreign operations. The data shows that there is a similarity in the major source of funds for both domestic and foreign operations.

On page 13 I have assembled the capitalization of the Respondents from pages 5 and 7, and show the cost of

debt and an estimated cost of preferred stock. Using this data I have calculated the return that would be allowed on the common equity when various overall rates of return are applied. I will explain later in my testi-

mony why I considered it necessary to use an estimated cost for the preferred stock.

In the two final pages I have included data to reflect the market action of oil company stocks included in the Standard & Poor's Stock Price Indexes, with 1941-1943—10, for oil companies, electric, gas and telephone utilities and also the composites for the "500", Industrials, Rails and Utilities. I converted the 1941-1943—10 index numbers to a basis of 1965-1967—100. The companies used in the indexes are published in the February 9, 1970 issue of Standard & Poor's *Outlook*. For convenience, I have listed on page 14 the companies in the oil company indexes.

Q. Mr. McGrath, how did you approach your study to arrive at a rate of return to be allowed the independent producers?

A. Since the rate of return evidence in AR61-2 is incorporated by reference in this case I started my analysis with a review of this data. It was my feeling that the most practical approach would be to use comparable

earnings as a guide, within the framework of the *Bluefield* and *Hope* cases.

By comparable earnings I do not mean only the earnings of pure independent producers but also the large integrated producers as well as utilities and industrial companies. I used the 17 pipeline companies who are Respondents as being representative of the pipeline industry. The total capitalization and the net income available for common equity for these companies is 75% of the total capitalization and net income available for common equity of the major Class A & B pipelines that

report to the Commission. The gas operating revenues of the 17 pipelines are 69.5% of the total for the major Class A & B companies.

As stated earlier, I updated the exhibit which Dr. Shaffner presented in AR61-2 and the current data is no win Exhibit No. 12 (JJM-1). Although that exhibit provides data useful in my analysis, I concentrated on obtaining information on companies that are Respondents in this proceeding when I developed Exhibit No. 13 (JJM-2).

I divided the 68 producer Respondents into those which were made Respondents by the Order of March 20, 1969, and those made Respondents by the Order of December 15, 1969. The first group of companies, 35 in number, are those that operate in the offshore area as well as onshore; the second

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group, 33 companies, includes companies which apparently have no offshore operations.

In addition to including information on all of the Respondents for whom data is available I also included information for all producers who are reported in FPC publication *Sales by Producers of Natural Gas to Interstate Pipeline Companies-1968* as selling 2,000,000 Mcf or more and for whom information was available to me. These producers are the 22 who are listed on page 9.

Q. Please continue with the description of your approach to the rate of return.

A. Along with my review of the testimony and exhibits in AR61-2, I reviewed Opinion No. 546, issued by the Commission on September 25, 1968, in that docket

and Opinion No. 546-A issued March 20, 1969. I considered the 12 percent rate of return allowed by the Commission in Opinion 546 as a point of departure, to be increased or diminished as my findings warranted. I also reviewed the Opinions in order to understand the Commission's approach in determining and applying the rate of return.

Q. What was the result of your analysis of Opinions 546 and 546-A?

A. The Commission found the 12 percent rate of return to be applicable to investment rate bases inherent in both

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a flowing gas coating method and a nationwide new gas-well gas coating method. In analyzing the Commission's new gas coating method I found the 12 percent rate of return applied to a rate base of 44.44¢ which gave a return of 5.33¢ per Mcf. The working capital was computed to be 1.60¢ per Mcf with a return of .19¢ In addition, the Commission added .15¢ to the .19¢ to give a total return on working capital of .34¢ which it rounded off to .35¢. The additional .16¢ was provided in order to allow producers sufficient cash to compete effectively in the market for new leaseholds.

Also, in arriving at a cost of 4.14¢ per Mcf for exploration and development costs, the Commission included an allowance of 1.12¢ "to provide the industry with the revenues needed to maintain the relationship between current findings and production". If the 1.12¢ is considered a return and is added to the returns of

.35¢ and 5.33¢ on working capital and production investment, respectively, the rate of return is 14.77% on the rate base of 46.04¢.

Q. Do you consider these allowances to be additional return?

A. No, but these allowances indicate that the Commission has provided some additional protection to the

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producers against future contingencies. For example, the total cost of service for new gas well gas in Opinion 546 amounted to 18.80¢ per Mcf including the items which I have just previously identified. However, gas well gas sold under contracts dated subsequent to October 1, 1968, would receive 20¢ per Mcf. I do not consider this additional allowance of 1.20¢ per Mcf to be an equivalent of return, but, it might be considered a protection against the contingency of future cost increases.

Q. What did you conclude from your review of the Commission's costing methods?

A. As I view these methods, the Commission provided additional allowances for operational contingencies that are peculiar to the production industry. I refer to the allowance of .16¢ it allowed for lease play and the 1.12¢ allowed for dry holes and exploratory costs.

Under these circumstances, where some contingencies have been provided for, I concluded that the fair rate of return on gas production investment should be based on an evaluation of the producer's position in the competitive markets for capital.

Q. What companies do you consider to be competitive with producers in the market for capital?

A. Actually, all companies have to be considered

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as competitive when one goes into the money market to obtain funds. Producers of gas and oil, just as electric utilities and natural gas companies must be in a position to offer a return to investors commensurate with the risk involved.

The exhibits presented in this hearing contain data on many industries and show that the investor has a wide range of investments open to him. One fact which stands out at the present time is the result obtained from a comparison of Schedules 3 and 4 of Exhibit No. 12 (JJM-1) with Schedules 8 and 8A of Exhibit No. 24 in AR61-2. Schedules 3 and 4 show an increase in the average rates of return on equity capital and a drop in the earnings instability index which indicates more stable earnings. The updating of the return on invested capital which appears on page 15 of Exhibit No. 12 (JJM-1) also shows an increase over the earlier data that appears on Schedule 24 of Exhibit No. 24 in AR61-2.

Q. What other changes did you find in comparing the 1962 data and the recent data?

A. One change that is quite noticeable is the increased use of debt by the oil and gas producers. At the end of 1962 the companies averaged approximately 14% of the long-term debt in their capitalization and by the

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end of 1968 it had increased to 20.5% as shown by page 1 of Exhibit No. 12 (JJM-1). Referring to Schedule No. 25 of Exhibit No. 24, in AR61-2, it can be seen that a 12% overall rate of return provided a return

of 13.34% to the common equity where long-term debt is 13.9% of total capitalization, and the imbedded cost of such debt is 4.02%.

Under the same 12% overall rate of return and the current debt ratio of 20.5%, the imbedded cost of debt and preferred stock would have to exceed 7% before the allowance on equity dropped below the 13.34%.

In discussing the capital employed by the twenty-eight companies in the group of companies it reported on, Chase Manhattan states on page 31 of its *1968 Annual Financial Analysis of a Group of Petroleum Companies:*

> "The 11.7 billion dollars of debt shown on the balance sheet does not represent the full extent of the Group's recourse to outside funds. Through the mechanism of long-term lease arrangements and production payments large sums of money are made available. If these funds were theoretically regarded as debt, the Group's debt to equity ratio would be about one-half larger than the 19 percent stated."

To increase the debt to equity ratio one-half larger than the 19% means that approximately $8,000,000,000 of debt is available to these companies but is not reflected on the balance sheets. This increase in the use of leverage

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would tend to increase the earnings on equity.

The use of preferred stock has increased slightly from 0.5% of total capitalization to 0.73% in 1968. The difference in percentage does not tell the complete story, however, because a substantial amount of the preferred stock issued since 1962 was issued under pooling of interests agreements. To cite one instance I refer you to page 4 of Exhibit No. 13 (JJM-2); opposite Atlantic

Richfield Company you will see 1.96% preferred stock in the total capitalization. This amount in dollars is $39,180,000 as taken from the balance sheet in the 1968 Annual Report to Stockholders. One issue of preferred stock, the $3 Cummulative Convertible Preference Stock, is recorded in the accounts at a par value of $3,980,000 and the annual dividend on it is $11,940,000.

Another instance would be Union Oil Company of California, it showed preferred stock outstanding at the beginning and end of 1968 at $108,797,000 and $107,-304,000, respectively. Cash dividends declared on these shares during 1968 were $24,914,000. This would indicate a dividend rate of about 23% on the average shares outstanding during the year.

These pooling of interest arrangements make it difficult to determine the actual cost of preferred stock and

this cost must therefore be estimated. In calculating the allowances on common equity on schedules in my exhibits I used an estimated cost of 6% for preferred stock.

Q. The companies you used in your exhibit have not been separated between producers only and integrated producers. What is your reason for not separating them?

A. After I collected the available data on all of the companies to be used I looked into the types of operations they were active in and it was my opinion that I would not be able to gather a group of companies that would be representative of producers only. The companies on page 9 of Exhibit No. 13 (JJM-2) include some small companies that more closely resemble pure producers than any other group. These small companies indicated a wide range of earnings including the six companies which I have separated out as reporting losses in the year 1968.

Q. Is this wide range of earnings you refer to an indication of a high risk involved in the production industry?

A. It could be an indication of high risk, but, you will notice that the companies on this page use more long-term debt in their operations than the larger integrated companies. This would seem to indicate less risk.

Ordinarily it is assumed that a thin equity would

deserve a greater return than a company with thicker equity, but, as stated in The Chase Manhattan Analysis I cited previously the balance sheet does not reflect the industry's full extent of the use of outside funds. The amounts I have included as long-term debt in my exhibits are those that were reported as such on the balance sheets and do not include production payments.

Q. Are there any significant changes taking place in the financing of oil and gas exploration activities?

A. Yes. At the present time there is a major change taking place in financing of the exploration for new sources of oil and gas. I am referring to the limited partnership arrangements which are now being offered to the public through oil and gas programs. The programs are usually managed by investment companies but occasionally they are managed by an oil company itself. These programs furnish speculative capital that an independent producer can use to spread the risk of exploration and at the same time maintain an interest in potential profits.

The programs are not novel but their use is expanding. In its issue of March 14, 1970, *Business Week* stated:

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Testimony of Commission Staff Witness John J. McGrath

"Where fewer than 40 funds sought less than $100 million from the public five years ago, 147 funds filed registrations with the Securities & Exchange Commission last year asking for more than $1.6 billion. Industry

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sources estimate that $750 million of this was actually collected—and they predict that this figure will more than double in 1970."

The activity in the programs has increased to the point where the Securities & Exchange Commission found it advisable to issue a "Guide for Preparation of Prospectuses Relating to Interests in Oil and Gas Programs" on January 19, 1970. All of the oil and gas program prospectuses with which I am familiar carry on the cover a statement either that the securities offered are "high risk" or "speculative".

Q. What consideration have you given to the fact that annual production of gas has exceeded discoveries of new gas supplies in each of the past two years?

A. I am aware of this situation. The American Gas Association recently reported that proved United States reserves of natural gas fell in 1969 for the second consecutive year, after twenty years of steady increase. This indicates to me the need for increased exploratory activity.

Q. Have you considered the existence or availability of foreign investment opportunities?

A. Yes. Large producers operate on a worldwide basis and there is the possibility that overseas operations

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are increased and the domestic operations are reduced because of a more attractive incentive. The chart shown on page 12 of Exhibit No. 12 (JJM-1) shows that the earnings on foreign invested capital have been in the same range as the earnings on domestic invested capital since 1964. I have used the data furnished in the Chase Manhattan Analysis and set out the capital structure used in the United States and in other countries. There is no appreciable difference in the proportions of debt and equity used in domestic and foreign operations. The return for 1968 on stockholder's average investment was 12.2% on investment in the United States and 12.3% on investment in other countries. This information is shown on page 12 of Exhibit No. 13 (JJM-2).

Q. You stated earlier that it was not possible to obtain a sample of pure producers. How will you proceed to determine the fair rate of return?

A. It is my opinion that, lacking a suitable basis for earnings of comparable companies, it is appropriate to look to other industries for a guide as to a fair return to gas producers. The differences in risk among industries make the problem more difficult. The returns on average equity which are shown on page 10 of Exhibit No. 13 (JJM-2) are principally for total operations of

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integrated oil and gas companies and I do not have information available to me to indicate what the returns were on gas operations alone. The rate of return I recommend is based on my consideration of the alternative investment opportunities open to producers and a

return to the producer which in my opinion would equalize the risk of the producer with the risk of other industries. Of course the risk involved in exploration and production for gas cannot be calculated in a mathematical formula.

To me the problem is to arrive at a rate of return that will be allowed producers of gas that will encourage investment in that industry as opposed to the investment of funds and experience in other industries.

Q. Have you considered the risks of exploration?

A. Yes, although I am sometimes puzzled by the statements I read in the public press. On several occasions I have read that a producer has claimed there is no shortage of gas, but it won't be found until the incentive is attractive. The fact that the gas is known to exist, and that the Commission allows all the costs of exploration and development appears to reduce the risks involved. At the same time I realize there is always a gamble in the exploration for gas. The cost of exploration and development allowed by the Commission in the cost of service might

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be exceeded by actual future costs experienced by producers.

Q. Have you considered alternative sources of gas?

A. This record contains a discussion of alternative sources of gas. I believe it is an accepted fact that the present cost of gas from other sources would be greater than for domestically produced natural gas. I feel that the ultimate consumer would benefit through the lower cost of domestically produced gas as opposed to alternative sources.

Testimony of Commission Staff Witness John J. McGrath

Q. What rate of return do you recommend to be used in these proceedings?

A. It is my opinion that an overall rate of return of 13% would be fair and reasonable. In arriving at this conclusion I have given consideration to the data in my exhibits as well as other sources which report financial and operating data. Page 15 of Exhibit No. 12 (JJM-1) gives an indication of earnings of other industries. If you will refer to page 13 of Exhibit No. 13 (JJM-2) you will find that a 13% rate of return provides an allowance on common equity of 15.49% based on the capitalization at December 31, 1968 of the sixty-eight Respondents for whom I have included data on my supporting schedules.

Q. How should this rate of return be applied?

A. I would expect the rate of return I recommend

to be applied in substantially the same manner as the Commission applied the rate of return in Opinion No. 546. I am assuming that the same approach to setting the cost of service for both new and flowing gas will be followed in this proceeding.

Q. Will the 13% rate of return you recommend assure an increase in the supply of gas for the future?

A. I cannot say that the 13% rate of return will assure an increase in gas exploration and consequently the supply. In my opinion the 13% rate of return and the approximately 15% return on equity will make an attractive investment. If this rate of return does not produce sufficient gas then some inducement other than the required financial return might be necessary.

Q. Does this complete your testimony?

A. Yes, it does.

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL POWER COMMISSION

AREA RATE PROCEEDING
(SOUTHERN LOUISIANA)
Docket No. AR69-1

PREPARED TESTIMONY OF JOHN C. JACOBS, JR.

Q. Please state your name and address.

A. My name is John C. Jacobs, Jr. My business address is Texas Eastern Transmission Corporation, P.O. Box 2521, Houston, Texas 77001.

Q. Mr. Jacobs, by whom are you employed and what is your present position?

A. I am employed by Texas Eastern Transmission Corporation and I am Senior Vice President.

Q. Are you also Chairman of the American Gas Association Committee on Natural Gas Reserves?

A. Yes.

Q. Have you been asked to testify in this proceeding by the UDC Group and to answer certain questions propounded by Mr. R. G. Gooch, General Counsel to the Federal Power Commission, in a letter dated March 16, 1970, and served on all the parties?

A. Yes, sir. In view of the apparent widespread desire that the methods of operation of the AGA Committee on Natural Gas Reserves be fully developed in the AR69-1 proceeding, I am happy to appear as a witness for the UDC Group.

Q. Please describe your educational background and experience.

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A. Educationally, I received a Bachelor of Science in Chemical Engineering degree from Georgia Institute of Technology in 1939 and a Bachelor of Laws degree from Yale University in 1948.

Professionally and on the legal side, I am a member of the American Bar Association, and am licensed to practice in the courts of Texas and Federal District Courts, Circuit Courts and the U.S. Supreme Court.

On the engineering side, I am a registered professional engineer in Texas, a member of Colegio de Ingenieros de Venezuela, a member of the Institute of Petroleum and the Institute of Gas Engineers in England, and hold memberships in the following U.S. societies: Society of Petroleum Engineers of the American Institute of Mining and Metallurgy Engineers, American Institute of Chemical Engineers, and the American Petroleum Institute.

As to the gas industry, I was a founder of the Wilcox Trend Gathering System in Texas and served as Executive Vice President from 1952 through 1955. From 1955 through 1966, I served as Vice President of Texas Eastern Transmission Corporation where my principal duties were concerned with gas supply. Since 1966, I have served as Senior Vice President of that organization as head of its Petroleum Division. I have been a member of the American Gas Association since 1955.

I have been associated with the estimation of reserves in one way or another since my initiation into this fraternity as a reservoir engineer of Creole Petroleum Corporation in Caracas, Venezuela, in 1944.

Q. Please briefly describe the American Gas Association.

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Prepared Testimony of John C. Jacobs, Jr.

A. The American Gas Association is one of the oldest industrial associations in the United States. It has among its members some 345 distribution companies located in every State of the Union, and supplying gas service in every major town and city of the country, except certain cities in Northern New England.

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The distribution companies which are members of the American Gas Association comprise some of the oldest utility operations in the United States. The earliest company has operated since 1816. Gas has been served by quite a few member companies from the middle 1800's.

Also included in the membership of the Association are most of the long-distance interstate transmission companies which carry gas from the producing fields to the distribution companies.

The American Gas Association was organized to assist its member companies in research, coordination of industry activities, and in the collection, coordination and dissemination of ideas and information. The AGA is recognized as one of the principal sources of authoritative statistical data on the gas industry in the United States.

Q. Please state the number of members in the AGA and, in answer to Question No. 1 in Mr. Gooch's letter, give the breakdown between distributors, pipelines, producers and others.

A. Information supplied to me by the headquarters staff of the American Gas Association on April 15, 1970, indicates that the AGA has 389 voting members made up of 345 domestic distribution companies, 13 foreign distribution companies and 31 domestic pipeline companies.

The AGA also has 5,400 individual members. In addition, there are 683 non-voting associate members. The associates are made up of 606 manufacturing companies, 55 consulting organizations, 17 producing companies and 5 financial organizations.

Q. When and why was the AGA Committee on Natural Gas Reserves established?

A. It was established in 1945 to provide the industry, the Government and the general public an annual estimate of the proved natural gas and natural gas liquids reserves of the United States.

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Q. What is the primary function of the Committee?

A. The Committee's primary function is to prepare an annual report entitled: REPORT OF THE COMMITTEE ON NATURAL GAS RESERVES OF THE AMERICAN GAS ASSOCIATION. This report essentially shows, in some detail, the reserves of natural gas and natural gas liquids at the beginning of the year, the extensions, revisions, discoveries and production during the year, and the reserves at the end of the year.

Annual publication of reserves and productive capacity is on a state total basis for the majority of the States, by geographical subdivisions of States in California, Louisiana, New Mexico and Texas, and a miscellaneous category comprising States having only nominal reserves.

Included in the Committee's report are estimates of productive capacity of gas and natural gas liquids by established regions. Special analyses are also made which categorize the current estimate of ultimate recoverable reserves by lithology of the reservoir rock, type of entrapment, geological age and by year of discovery. The

description of these statistics and the procedure used in their determination and compilation are detailed within the report. I will more fully explain the content of the report throughout my testimony.

Q. Will you please explain how and when the results of your Committee's studies are published.

A. The annual report of oil, gas and natural gas liquids reserves of the United States and Canada is published jointly by the American Petroleum Institute, the American Gas Association and the Canadian Petroleum Association in a report entitled: RESERVES, OF CRUDE OIL, NATURAL GAS LIQUIDS, AND NATURAL GAS IN THE UNITED STATES AND CANADA. The AGA Committee on Natural Gas Reserves report is coordinated for publication with the other associations' reports by the Department of Statistics of the American Gas Association.

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developed a report on the producing capabilities of petroleum and natural gas for the National Petroleum Council. Since 1965, I have been a member of one of the subcommittees of the API Statistics Committee. In 1965, this group cooperated in conferences which resulted in revamping the API annual crude oil reserve report and the AGA gas reserves report to expand considerably the amount of data published and to develop detailed definitions and procedure descriptions for the two Committees.

Q. What are your duties as Chairman of the Reserves Committee?

A. My duties are to select, from the many excellent candidates available, the best for Committee membership, to appoint the members of the Committee, to co-

ordinate the activities of the Committee and to supervise the preparation of the Report.

Q. Will you please describe the organizational structure of the Committee.

A. The nation is divided into 10 geographical districts, each of which is under the jurisdiction of a member of the Committee. The reserves for each of these districts are determined by a Subcommittee comprised of the Committee member and a Subcommittee which he, in turn, appoints and supervises. The reserves so determined for the several districts are then added together to get the reserves for the nation as a whole.

Q. Will you please describe the geographic districts.

A. The geographic districts of the United States assigned to Reserve Committee members and their Subcommittee sub-districts are as follows:

1. *Appalachian Area*
   Kentucky, Maryland, New York, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia
2. *Southeast Area*
   Alabama, Florida and Mississippi

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3. *South Central Area*
   Arkansas and North Louisiana
4. *South Louisiana Area*
   South Louisiana including the Offshore Area
5. *Texas Gulf Coast Area*
   Texas Railroad Commission Districts 1, 2, 3, and 4, including the Offshore Area

6. *Northeast Texas Area*
   Texas Railroad Commission Districts 5, 6, 7B and 9

7. *West Texas-Southeast New Mexico Area*
   Texas Railroad Commission Districts 7C, 8, 8A and Southeast New Mexico

8. *Mid-Continent Area*
   Illinois, Indiana, Iowa, Kansas, Oklahoma, Michigan, Minnesota, Missouri and Texas Railroad Commission District #10

9. *Rocky Mountain Area*
   Colorado, Montana, Utah, Wyoming, Northwest New Mexico, Nebraska, North Dakota and South Dakota

10. *Pacific Coast Area*
    Alaska, Arizona, Oregon, Washington and California, subdivided into San Joaquin Valley Region including the Sacramento Valley Area, the Coastal Region and the Los Angeles Basin Region

Q. Please describe the Subcommittee organizations appointed and supervised by the Committee members for each district.

A. The Subcommittees, which are responsible for the determination of reserves, are in all cases composed of geologists and reservoir engineers. They are experienced in reserve determination and have intimate knowledge of the areas assigned to them. They also have available to them detailed information of industry operations and developments. Subcommittee men are appointed by the Chairman of the Subcommittee with the approval of the Chairman of the Committee.

Prepared Testimony of John C. Jacobs, Jr.

To provide continuity, Subcommittee membership is normally retained by each individual so long as the assignments are properly discharged and the policies of the Committee are observed. Each individual is expected to serve

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only as long as he retains an affiliation with the oil and gas industry in an active capacity which enables him to make a contribution to the work of the Committee or Subcommittee.

Q. Whom did you, as Chairman, appoint to the Committee after your appointment in 1969? Please state in each case how long these men have served on the Committee. This is also covered by Mr. Gooch's Question No. 2.

A. The names, company affiliation and years of service (on the Committee itself, plus years of service on Subcommittees) of the Committee which prepared the Reserve Report as of December 31, 1969, are as follows:

D. S. Colby—U.S. Bureau of Mines—20 years

P. A. Cole—Cities Service Gas Company—23 years

B. B. Gibbs—United Gas Pipe Line Company—23 years

F. C. Hauber—Consolidated Natural Gas Service Company, Inc.—17 years

J. R. Jordan—Lone Star Gas Company—5 years

W. C. Lonquist, Jr.—Texas Eastern Transmission Corporation—2 years

M. G. Martin—Texas Gas Transmission Corporation—16 years

J. N. Newmyer—Gulf Oil Corporation—10 years

D. R. Scherer—Southern Natural Gas Company—14 years

H. C. Steele—Humble Oil & Refining Company—9 years
M. T. Whitaker—Mobil Oil Corporation—24 years
A. H. Wieder—Shell Oil Company—20 years
T. I. Gradin (Secretary)—American Gas Association—11 years

Notice that, of the fourteen members, six work for pipeline companies, 4 work for producing companies, 2 work for distribution companies, 1 works for an agency of the United States Government, and one is a member of the staff of the American Gas Association.

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Q. Please state the current membership of the several Subcommittees. This is also covered by Mr. Gooch's Question No. 3.

A. My Exhibit 19 sets forth the names of the men currently serving on the Subcommittee. The list consists of 109 men, 7 of whom are members of two Subcommittees and one of whom is a member of three Subcommittees.

To this total of 118 committeemen, one should add the 4 members of the Committee who are not Subcommittee Chairman to get a total of 122 Committee or Subcommittee members. Of this total, 31 work for pipeline companies, 7 for distributing companies, 62 for producing companies, one for the United States Government and one is a staff member of the American Gas Association.

Q. Does the Committee take overall responsibility for the reserves reported in each of the geographic districts and subdistricts mentioned?

A. Yes, sir.

Q. Are Committeemen, Subcommitteemen, or their employing companies, required to be members of AGA?

A. No, sir. Our primary concern in all cases is to secure the services of qualified and experienced geologists or engineers thoroughly grounded in reserve estimation who have a familiarity with the area with which they will be dealing. Membership in the AGA is not required.

Q. Are the services of the Committeemen and Subcommitteemen voluntary and unpaid?

A. Yes.

Q. In Question No. 5, Mr. Gooch asks that you explain the working procedures of the Committee and Subcommittees. I will have several questions

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bearing on this matter, and the first is this: When does your Committee meet and please describe the purpose of such meetings.

A. The Committee has two scheduled meetings each year, once in the fall and once in the spring. Special meetings are held when needed.

The fall Committee meeting provides for review of developments affecting the Committee responsibilities and better coordination of the overall effort. The results of Subcommittee studies are submitted to the Committee for review at the spring meeting which is held concurrently and at the same location as the meeting of the American Petroleum Institute Committee on Reserves and Productive Capacity.

Attendance by Subcommittee members at all meetings of the Committee is encouraged. Subcommittee members participate freely in the deliberations and discussions.

Representatives of the Canadian Petroleum Association Reserves Committee meet with the AGA Committee on Natural Gas Reserves and report changes in the

status of Canadian Reserves for inclusion in the jointly-published report.

Q. Please describe the general procedure by which the reserve estimate for each geographical district is prepared by the subcommittee responsible for such district.

A. The Member of the main Committee who is the Chairman of the Subcommittee assigns all of the known fields within the district among the several Subcommittee members. Initially, each Subcommittee member is individually responsible for preparing the reserve estimate for the fields assigned to him.

The Subcommittee member, who, in all cases, is an experienced reservoir engineer or geologist, goes about his work in such way as he deems best

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within recognized principles of reservoir engineering. He is to use all available data which he deems reliable in the preparation of his reserve estimate from both private and public sources. His assignment may cover properties owned by his employer as well as properties owned by others.

The reports of the individual Subcommittee members are then presented at a meeting of the full Subcommittee. Here, the individual reports are subjected to review and discussion.

On the basis of this review and discussion, the Subcommittee then adopts a reserve figure for each field within the geographical district and the figures so adopted are then cumulated in the Subcommittee report for that geographical district.

Q. Mr. Gooch's Question No. 4 is as follows: "Are there any other persons, such as observers, who par-

ticipate either officially or unofficially in the work of the Committee or any Subcommittee?

A. Meetings of the Committee and Subcommittees are attended only by the Committee and Subcommittee members, it being the position of the Committee that only these actual members can make a contribution to the work being done.

Q. How and when are Subcommittee meetings scheduled?

A. Subcommittee meetings are scheduled by the Subcommittee Chairman as and when he deems best to provide coordination of the work and timely reporting of the reserves and productive capacity determination.

Q. Do you have knowledge of the figures for individual fields as determined by the Sucommittees?

A. No. The Subcommittee Chairmen report to me only the total figures for their respective areas.

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Q. Will you please define "Natural Gas" as the term is used by the Committee.

A. For the purpose of the Committee report, natural gas is defined to be a mixture of hydrocarbon compounds and small quantities of various non-hydrocarbons existing in the gaseous phase or in solution with oil in natural underground reservoirs at reservoir conditions. The principal hydrocarbon usually contained in the mixture are methane, ethane, propane, butanes and pentanes, and typical non-hydrocarbon gases which may be contained in reservoir natural gas are carbon dioxide, helium, hydrogen sulphide, nitrogen, etc.

Q. Have you further recognized different types of gas?

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A. Yes. Natural gas is classified by the Committee in two categories based on the type of occurrence in the reservoir, as follows:

1. Non-associated gas is defined as free natural gas not in contact with crude oil in the reservoir;
2. Associated-Dissolved gas is the combined volume of natural gas which occurs in crude oil reservoirs either as free gas (associated) or as gas in solution with the crude oil (dissolved).

Associated gas is free natural gas, commonly known as gas cap gas, which overlies and is in contact with crude oil in the reservoir. Dissolved gas is natural gas which is in solution with crude oil in the reservoir at original reservoir conditions.

Production of associated gas usually affects to some degree the ultimate recovery of crude oil by reduction of the gas cap volume and loss of reservoir pressure. Where the production of associated gas from gas wells does not have a significant effect on the crude oil recovery, such associated reserves may be classified as non-associated gas by regulatory body ruling or company

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operating practice. In such cases, this classification is also followed in the report of the Committee.

Production and productive capacity of associated and dissolved gas is generally more closely related to the production of crude oil than to the available market for gas. Since only rough estimates for the separation of the production of commingled associated and dissolved gas produced oil wells can be made as a portion of the dissolved gas may change classification in the reservoir

during depletion of the oil reserve, the Committee has combined the reserves and production capacity of Associated and Dissolved gas into a single category known as Associated-Dissolved. Free gas contained in the reservoir after depletion of the oil reserve is reclassified to the non-associated category. In such cases, the gas reserves are determined on the basis of the remaining gas reservoir volume and conditions existing at the time of depletion of the oil reserve.

Q. What is the nature of the reserves reported by your Committee?

A. The reserves contained in the Committee report are natural gas and natural gas liquids reserves estimated to be recoverable from proved reservoirs under the economic and operating conditions existing at the time of the estimate. Such volumes of gas, as well as all other gas statistics, are expressed in cubic feet at 14.73 pounds per square inch absolute pressure and 60°F temperature. The liquids are expressed in stock tank barrels of 42 U.S. gallons. These reserve estimates constitute an annual inventory of proved reserves which include gas and natural gas liquids reserves of all types regardless of size, availability of market, ultimate disposition or use. The statistics on natural gas reserves and production reported by the Committee take into account the shrinkage of the reservoir gas volume resulting from the removal of the liquefiable portions

of the hydrocarbon gases and the reduction of volume due to the exclusion of non-hydrocarbon gases where they occur in sufficient quantity to render the gas unmarketable.

Attention is called to the fact that natural gas is a mixture of hydrocarbon compounds and small quantities of various non-hydrocarbons. In most cases, the quanities of non-hydrocarbons are *de minimis* and do not affect the marketability of the gas. In such cases, no reduction in volume for the theoretical removal of such non-hydrocarbons has been made. In any reservoir where the quantity of non-hydrocarbons is sufficient to render the particular gas unmarketable, an appropriate reduction in the reservoir gas volume has been made to cover the exclusion of such non-hydrocarbons.

Q. The report refers to the reserves reported as "proved reserves." Will you please define this term as used in the report.

A. Yes. The Committee defines proved reserves as the current estimated quantity of natural gas and natural gas liquids which analysis of geologic and engineering data demonstrate with reasonable certainty to be recoverable in the future from known oil and gas reservoirs under existing economic and operating conditions. Reservoirs are considered proved that have demonstrated the ability to produce by either actual production or conclusive formation test.

The area of a reservoir considered proved is that portion delineated by drilling and defined by gas-oil, gas-water contacts or limited by structural deformation or lenticularity of the reservoir. In the absence of fluid contacts, the lowest-known structural occurrency of hydrocarbons controls the proved limits of the reservoir. The proved area of a reservoir may also include the adjoining portions not delineated by drilling but which can be evaluated as economically productive on the basis of geological and engineering data available at the time

the estimate is made. Therefore, the reserves reported by the Committee include total reserves which may be in either the drilled or the undrilled portions of the field or reservoir.

The Committee's proved natural gas and natural gas liquids reserves do not include:

1. Gas and natural gas liquids whose recovery is subject to reasonable doubt because of uncertainty as to the geology and/or reservoir characteristics;
2. Gas and natural gas liquids which may exist in untested prospects and reservoirs;
3. Natural gas liquids which will be recovered with crude oil in the field separator; and
4. Natural gas liquids produced and reinjected in an underground reservoir, either in connection with improved oil recovery operations or for storage in underground resevoirs or solution cavities.

Q. Mr. Gooch's Question No. 21 asks: "Could proved reserves be divided so as to show those which are:

(a) Committee to interstate pipelines
(b) Committed to the intrastate market
(c) Contracted to direct industrial consumers
(d) Uncommitted."

What is your answer?

A. No. The only reserve data in the hands of the Committee on Natural Gas Reserves and its Subcommittees are for total reservoirs and fields. The Committee has no knowledge of the ultimate disposition of these reserves.

Q. You state that "reserves are considered proved that have demonstrated the ability to produce by either actual production or conclusive formation test." Have

the standards by which this test is applied been changed at any time, Mr. Jacobs?

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A. No.

Q. Absent actual production, what would constitute a "conclusive formation test" which would prove up reserves?

A. A drill stem test, wire line test or production test on completion, in which natural gas was produced or recovered under conditions which would remove any reasonable doubt as to the formation being tested containing and being able to produce natural gas.

Q. In his Question No. 23, Mr. Gooch asks: "What distinction is there between 'proved reserves' as reported by the AGA and 'marketable reserves' as reported by the Reserves Committee of the Canadian Petroleum Association? Could you provide an estimate of 'marketable reserves' for the continental U. S.?" Please state your answer.

A. The AGA Committee on Natural Gas Reserves' definition of "proved reserves" defines the current estimated quantity of natural gas and natural gas liquids which analysis of geologic and engineering data demonstrate with reasonable certainty to be recoverable in the future from known oil and gas reservoirs under existing economic and operating conditions. Reservoirs are considered proved that have demonstrated the ability to produce by either actual production or conclusive formation test.

The Canadian Petroleum Association definition of marketable gas is raw gas from which certain hydrocarbon and non-hydrocarbon compounds have been removed or partially removed by processing, where necessary to

meet pipeline or other market specifications. Marketable gas is often referred to as pipeline gas, residue gas, or sales gas.

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My understanding is that the principal differences between the AGA and Canadian figures lie in the fact that the AGA includes and Canada excludes (a) field use including flared gas and (b) small reserves at long distances from pipeline systems. On the basis of the methods and procedures governing the AGA Committe, it is not possible to provide an estimate of marketable production.

Q. In his Question No. 24, Mr. Gooch asks: "Do revisions in proved reserves of associated-dissolved gas always result in equivalent revisions in oil reserves? If not, please explain." Please state your answer.

A. No. Reserves of associated-dissolved gas may be changed, without a change in oil reserves by (a) revising the gas/oil ratio, (b) revising the estimate of the size of an associated gas cap, and (c) reclassification of gas production from certain wells.

Q. You have in several of your previous answers stated that proved reserves are those than can be produced under prevailing "economic and operating conditions." Mr. Gooch's Question No. 15 asks: "Explain what is meant by 'under the economic and operating conditions existing at the time of the estimate.'" What is your answer?

A. The phrase "under the economic and operating conditions existing at the time of the estimate" means that reserve estimates are made to reflect current producing practices as determined by today's technology and economic situation and not by some assumed future

conditions. Economic and operating conditions influence the recovery factor used in the reserve estimate. The usual questions to be answered are the amount of compression and/or processing to which this gas will be subjected. For example:

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> In a given area, the main lines of gas purchasing companies operate at 1,000#. For a long time, no more than one stage of field compression has been installed as wellhead pressures declined. In these circumstances, an abandonment pressure of 400-500# might properly be assumed.
>
> However, in another area scarcity of gas and field performance may have resulted in instances of fields being pulled on a vacuum. In these instances, an abandonment of 0# would be used.

I might emphasize that we are dealing here with reserves of existing fields where economic factors have less effect than in exploratory efforts to find new fields.

Q. In Question No. 16, Mr. Gooch asks: "Would a change in the price level of natural gas cause a change in the Committee's estimate of reserves recoverable 'under existing economic and operating conditions'?" What is your answer?

A. In some cases, yes. For example, an increase in the price level of natural gas might justify additional compression which, in turn, might increase the recovery factor of the fields to which the compression was applied.

Q. Now will you please define "discoveries", Mr. Jacobs, as that term is used by your Committee.

A. Discoveries are defined as proved reserves in newly-discovered fields and newly-discovered reservoirs in old fields. New reservoir discoveries include proved reserves in new segments of reservoirs that are separated from the previously-proved productive area by faulting, lenticularity of the reservoir, or other subsurface discontinuity. Reserves of multi-reservoir fields, included in the new field discovery category, reflect the reserves of all reservoirs proved during the discovery year of the field. New discoveries seldom are delineated or fully developed during the year of discovery. Therefore, the year-end reserves

estimates of discoveries generally represent only a part of the reserves that ultimately will be assigned.

Q. Mr. Gooch's Question No. 12 asks: "When a discovery is made, how long does it take for these reserves to be reported to the AGA? How long is it before such reserves are then reported by the AGA?" What is your answer?

A. Reserves for all known discoveries made during a calendar year are included in the annual year-end reports of the Committee on Natural Gas Reserves, provided adequate data are available in time to make a reserve estimate for such report. In the event such data are not available in time for the report, reserves for the discovery will be included in a subsequent report just as soon as the necessary data are available.

Q. Next, will you please define "extensions" as that term is used by your Committee, Mr. Jacobs.

A. A discovery in one year normally is delineated by the drilling of both extension and development wells dur-

ing subsequent years. Drilling usually continues until the productive limits of the field or reservoirs are defined. Increases in the proved area of reservoirs result in appropriate adjustments to estimates of recoverable reserves and such changes are recorded under extensions.

Q. Now, please define "Revisions", Mr. Jacobs, as that term is used by your Committee.

A. The drilling of additional wells in a reservoir not only delineates the productive area but also provides additional basic geological and engineering data. Estimates of porosity, interstitial water, pay thickness and other reservoir factors may be revised by new data. Analysis of the producing history of a reservoir, including production of oil, gas and water, and pressure performance results in more accurate concepts concerning the producing mechanism,

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recovery efficiency and the performance of the reservoir. The composite of the new and improved information will yield more precise estimates of the ultimate recoveries and remaining reserves, and result in revisions to previous estimates. Changes in reserve estimates brought about by the application of cycling or other recovery techniques are also included in revisions to reserves. Also, changes in reserves resulting from a reduction in the estimate of the proved area are included in revisions.

Q. Mr. Gooch's Question No. 25 asks: "What are the major factors which determine the need for 'revisions'?" What is your answer?

A. The two major factors determining the need for revisions are producing history and data obtained from additional drilling.

Q. Mr. Gooch's Question No. 17 asks whether "revisions" reflect "changing economic conditions." What is your answer?

A. Yes. For example, as explained in the response to Mr. Gooch's Question No. 15, if additional compression becomes economic, the recovery factor for a field might be increased and, in consequence, a revision upward would be called for.

Q. Mr. Gooch's Question No. 26 asks: "Are Committee and Subcommittee members instructed to report revisions promptly upon discovery, or do they have some leeway in accumulating revisions until the amount is large?" What is your answer?

A. Committee and Subcommittee members are instructed to report all known revisions in each annual report.

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Q. Mr. Gooch's Question No. 27 is as follows: "Are revisions uniformly reported for the year in which they are made, or might there be a delay until a subsequent year before actually published?" What is your answer?

A. Revisions are always reported for the year in which they are made by the Committee.

Q. Mr. Gooch's Question No. 29 is: "If as a result of technological development additional volumes of gas may be economically produced, are such additional volumes reflected in 'revisions'?" What is your answer?

A. Yes. Hydrofracing is a good example.

Q. Coming now to the matter of "net production", what is the definition of that term as used by the Committee, Mr. Jacobs?

A. Net production as defined by the Committee is production which constitutes the total volume of natural gas withdrawn from producing reservoirs less the vol-

ume returned to such reservoirs in cycling, repressuring of oil reservoirs and conservation operations. Net production as reported by the Committe is corrected for shrinkage resulting from the removal of the liquefiable portions of the gas and excludes non-hydrocarbon gases where they occur in sufficient quantity to render the gas unmarketable. Net gas production is not comparable to marketed gas volumes because a portion of the gas withdrawn from reservoirs is consumed in field operations as lease and plant fuel. Also, some gas is vented.

In many instances, the production statistics for natural gas are available only on a total produced basis including all or a part of the liquefiable portions. In such cases, the individual Subcommittee makes the appropriate adjustments to conform to the Committee's definition of gas production.

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Reported production of natural gas liquids includes liquids recovered by field separation facilities on an individual lease basis and liquids recovered by plant facilities on a total plant basis. In cases where plants process gas from more than one field, plant yields are allocated to gas production and reserves of fields connected to such plants. Where the liquid content of gas from a specific field is known to vary from the average plant yield, proper adjustments are made for production and reserve statistics. Where it is impossible to determine the separate sources of gas processed by a plant, gas liquids reserves and production are estimated on a total plant or area basis.

Volumes of gas withdrawn from gas storage reservoirs are not considered as production since this gas has been previously recorded as production when with-

drawn from the original natural reservoirs or is native gas which has been transferred to the storage category.

The net change in volumes of underground storage gas, which represents the balance of the volumes injected and withdrawn from such reservoirs and volumes transferred to the storage category, is reflected in the annual change in status of reserves as reported by the Committee. Net production as previously defined relates specifically to the depletion of the proved gas reserves of the natural reservoirs.

Accurate production statistics for many of the earlier years are not available as the data recorded in the public record includes only marketed production and not the total withdrawals from fields and reservoirs. In order to report a realistic cumulative production of gas and natural gas liquids, it has been necessary to supplement the data obtained from various State conservation commissions by production data from individual company records, oil

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scout reports and other sources. In cases where it is impossible to determine cumulative production from recorded data, such production is determined by the difference in current estimate of ultimate recoverable reserves at original reservoir conditions and the estimate of the remaining recoverable reserves at current reservoir conditions.

Thus, the Committee's report reflects estimates of the cumulative production by established regions to December 31, 1964, and actual production for succeeding years. Annual production and cumulative production, as reported herein, represent the most accurate and complete data available. The Committee has relied upon produc-

tion reports required by State agencies wherever available. In those cases where State reports cannot be used, data have been obtained from all available reliable sources, including direct reports from companies, conservation committees, oil scout associations and others. The Subcommittees have made any adjustments necessary for consistency and for agreement with the definitions of production set out herein in the section headed 'Natural Gas and Natural Gas Liquids Production.'

The Subcommittees, through necessity, must use preliminary estimates of production for timely reporting of current year reserves and other statistics. This estimate of annual production is adjusted to actual in the succeeding year for reporting historical annual and cumulative production. Reserves previously reported will not be changed because of this adjustment in production; however, a revision of reserves will be included in the estimated reserves for the current year to compensate for such variance in the preceding year.

Q. As to production, Mr. Gooch asks in Question No. 19: "Please explain the meaning of the negative figures for associated-dissolved production for

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Alaska at page 221 (Table XVIII 2) of the 1968 AGA annual report." What is your answer?

A. In Alaska, non-associated gas is injected into the oil reservoirs in pressure maintenance projects in greater quantities than associated-dissolved gas is produced. Since the non-associated gas is counted as "production", the overall result must be a negative figure for associated-dissolved production.

Q. Your Committee reports the ultimate recoverable

reserves by year of discovery, Mr. Jacobs. Will you please explain how this is done?

A. Yes. The compilation of ultimate recoverable reserves includes data on both producing and depleted fields by years of discovery. The volume of reserves credited to each year represent the current estimate for fields discovered in that year and are reported for the pre-1920 period and by years thereafter. These statistics do not represent new or original findings with respect to reserves of the United States but are a recasting of the current estimates as of December 31 of each year.

As the estimates of reserves of discoveries will be revised in time, the historical data presented is not a final analysis of discovery trends.

The procedures for compilation of these data are consistent with those used by the National Petroleum Council in its reports on "Proved Discoveries and Productive Capacity" of 1961 and 1965.

The historical compilation of discoveries is usually on a field total basis; therefore, reserves of new reservoir discoveries, reported in the current year reserve statistics, are considered additions to reserves of those fields in this tabulation and are given the discovery date of the field. However, it is also appropriate to give later discovery dates to certain

hydrocarbon accumulations which are significant from the standpoint that advances in exploration technology resulted in the discovery of such reservoirs. Also, reservoirs prorated at separate fields may be included in their specific year of discovery.

Discovery dates of fields may be changed as the result of new information. Two fields discovered at different

dates and later found to be connected to form one field would result in the reallocation of the reserves of the second field to the discovery year of the older field.

Q. As to ultimate recoverable reserves estimates in teh reports for the years 1966 and 1967, Mr. Gooch's Question No. 18 asks: "Please explain why there is a difference of almost 6 trillion cubic feet between the total ultimate recoverable discovered gas reserves for the year-end 1967 and the sum of the total ultimate recoverable discovered gas reserves for the year-end 1966 plus the annual reserve additions for 1967." What is your answer?

A. The reason for the difference in ultimate reserves is that, in its 1967 Report, the Committee made a change in its estimate of the cumulative production which occurred in years prior to 1967, for the most part in depleted fields.

Any such correction of cumulative production that does not affect the remaining reserve would not appear as a "revision" to remaining reserves and, hence, would not be reflected in the reserve additions in 1967.

For example—If it were found that the cumulative production in a depleted field was incorrect, then a correction would affect the ultimate reserve but would not affect the zero remaining reserve for such field.

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Q. Mr. Jacobs, we have run through the general framework of the Committee Reserve Estimates and I would like to turn now to the statistical accuracy of the reports. Is this one of your particular functions?

A. Yes. My job as Chairman carries the responsibility of seeing that a statistically-accurate report is produced.

Q. In Question No. 13, Mr. Gooch asks for a description of the AGA procedures to this end. Can you furnish this?

A. Set forth below is a compendium of the checking and other procedures followed by the Committee to insure that the report is accurate.

1. Each individual table must be in balance.
2. The sum of Tables II and III must equal Table I with the exception of underground storage.
3. The sum of Tables V and VI must equal Table IV.
4. The beginning reserves on Tables I, II, III, IV, V and VI in each year must be the same as the ending reserves of the previous year.
5. Beginning reserves on Table I in each year plus extensions, revisions, new field discoveries, new reservoir discoveries and net change in underground storage, less preliminary net production must equal the reserves at the end of the year.
6. Tables II, III, IV, V and VI must balance as in Item 5 with the exception of net change in underground storage.
7. The volumes shown in the current year of Table XVII must be as large as the volumes shown for the appropriate State or subdivision in Column 4 on Tables I, II and III but no larger than the sum of Columns 4 plus 5.
8. Net change in underground storage on Table I must equal the difference between the current year underground storage volume and the underground storage volume published for the previous year.

9. The volumes shown for each year on Table VII must equal the volumes published for the corresponding year on Table I.

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10. The volumes shown for each year on Table VIII must equal the volumes published for the corresponding year on Table II.
11. The volumes shown for each year on Table IX must equal the volumes published for the corresponding year on Table III.
12. The volumes shown for each year on Table X must equal the volumes published for the corresponding year on Table IV.
13. The volumes shown for each year on Table XI must equal the volumes published for the corresponding year on Table V.
14. The volume shown for each year on Table XII must equal the volumes published for the corresponding year on Table VI.
15. The volumes shown as total gas reserves for each year on Table XIII must equal the volumes shown as estimated proved reserves as of year end for the corresponding year on Table X.
16. The sum of Tables XIII—2 through XIII—45 for each year must equal the volumes shown on Table XIII—1 for the corresponding year.
17. The total of the ultimate reserves shown for each State or subdivision on Tables XIV, XV and XVII must be equal. The total ultimate reserves shown for total United States on Tables XIV, XV, XVI and XVII must be equal.

18. The sum of Tables XVII—2 through XVII—45 for each year must equal the volumes shown on Table XVII—1 for the corresponding year.
19. Table XVII—1 through 45. See Item #7.
20. The sum of Tables XVIII—2 through XVIII—45 and Tables XIX—2 through XIX—45 for each year must equal the volumes shown for the corresponding year and product on Tables XVIII—1 and XIX—1.
21. The cumulative total of production shown for the previous year on Table XVIII—1 through XVIII —45 for each State or subdivision plus the preliminary production shown for the current year on Tables I, II and III, plus the remaining rereserves of the current year for the corresponding State or subdivision shown on Tables I, II and III must equal the total ultimate reserve shown on Tables XIV, XV and XVII for the corresponding State or subdivision.
22. A comparison is made of the daily average production for each State or subdivision with the productive capacity shown on Table XX. In most instances, the productive capacity should be as large as, if not greater than the daily average production.

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Q. In Questions 20 and 28, Mr. Gooch asks about certain errors in the prior reports. Question No. 20 is as follows: "New field discoveries for Texas R. R. Commission District No. 9 are listed on page 120 of the 1968 AGA annual report at 5,635 million cubic feet. How-

ever, estimated additions to ultimate recoverable gas reserves for that district are listed on page 213 as only 2,819 million cubic feet. Please explain why the second figure is considerably below the first." What is your answer?

A. A new field discovered in 1967 in Texas Railroad Commission District No. 9 was overlooked in the 1967 report. The field was, therefore, listed as a 1968 discovery in Table I of the 1968 report. In order that Table XVII be accurate, the reserve was recast to 1967 in the 1968 report.

Q. In Question No. 28, Mr. Gooch asks: "Have there been any errors similar in magnitude to the failure to subtract 1967 production of 650 million cubic feet from Texas R. R. Commission District No. 10 revisions until 1968? If so, please list and explain." Please state your answer.

A. I know of no such errors.

Q. Now that you have covered the general procedures, I would like to turn to the matter of the relation between the Committee and Subcommittee members on one hand and the employers of these men on the other. The testimony has indicated that these men are employed by distributing companies, pipeline companies, producing companies, the United States Government and the American Gas Association. My question is this: do the employers of Committee or Subcommittee members or the officials of such employers have any voice in Committee procedures or standards?

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A. Such employers or officials have no voice whatsoever.

Q. Has there been any dictation of the methods, procedures, standards or organizational arrangement of the Committee by any person outside the Committee?

A. No. The Committee on Natural Gas Reserves and its Subcommittees were set up for the single purpose of providing the public with the best possible estimate of the proved reserves of natural gas in the United States of America. It was never thought that a perfect reserve estimate could be produced, but the organization, procedures and standards have been designed by the Committee itself to provide the best possible figure. Following are some of the considerations which were of paramount importance:

(a) The task of annually preparing estimates for new discoveries and reviewing estimates on old discoveries for every gas well in the United States is one of tremendous magnitude.

(b) No funds are available to pay for work of this magnitude so the organization had to be voluntary and data storage held to a minimum.

(c) To get the best results, it is necessary to have access to the best of the large number of reservoir engineering experts in the United States and access, to the maximum extent possible, to all known data.

(d) Since certain of the necessary data are characterized by a proprietary interest which the owning companies demand be protected, the system must respect certain confidentiality standards as to the disclosure of data.

(e) In order to provide the best sound and reasonable reserve figures, the system should provide for a continual review of the estimates made.

With these considerations in mind, the Committee has been organized and the standards set as I have described. The decisions as to exact definitions and procedures have been set by the professional geologists and engineers

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—exercising their judgment after discussion—who have comprised the Committee over the 25 years of its existence. There have been no dictation of methods, procedures, standards or organizational arrangement from the outside.

Q. Do the employers of Committee members or officials of such employers have any voice in the selection or tenure of any Committee or Subcommittee member?

A. Absolutely none.

Q. It may be noted from your previous testimony that some members of the Committee or Subcommittees are employed by companies which are not members of the American Gas Association. Why is this so?

A. This is so in order that the Committee may have access to all of the best reservoir engineering talent in the country, and so it may have access to the greatest amount of available data.

Q. Now, coming to the relation of producers as such to the estimate, in Question No. 7, Mr. Gooch asks: "Do you obtain from producers pressure data, permeability data, porosity data, sub-surface maps, recovery factors, etc.? Is this data sent to the AGA or to the applicable Subcommittee, or is it examined in the producing Company's offices?" What is your answer?

A. In accordance with established Committee procedures, the Subcommittee receives the individual estimates of the reserves in the assigned field from the

Subcommittee member to whom the assignment was made. The subcommittee member making the estimate obtains his data from all reliable sources available to him. Data are examined in whatever circumstances or locations, including producing-company offices, the Subcommittee member making the estimate finds convenient and necessary. Data of the type mentioned in the question are never sent to either the AGA or to the Subcommittee.

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One should remember that the Committee on Natural Gas Reserves is a voluntary Committee which has no funds, no offices and no storage space for data.

Q. Mr. Gooch asks in Question No. 8: "Do producers submit a reserve estimate along with the engineering and geological information?" What is your answer?

A. As has already been pointed out, this never occurs. Instead, the Subcommittee member is charged with preparing an estimate from whatever are the best sources of data available to him. Such data sources should, of course, include producers.

Q. Mr. Gooch asks in Question No. 9: "If the American Gas Association estimate for extensions, revisions, new fields or new reservoirs in a particular instance conflicts with that of the producer, which estimate is used?"

A. Under Committee procedures, no such conflict is possible since no estimates are submitted by producing companies.

Q. Are there situations in which the owner of certain data obtained by drilling might refuse to permit the use of such data by a Subcommittee member?

A. Obviously, when certain data may be the key to the value of unleased tracts, such data may have a high

value to their owner. The data may also have a high proprietary value for reasons such as their involvement in unitization proceedings. Under these circumstances, the owners might properly decide to withhold temporarily such data from any outside party including our Subcommittee member.

The possible magnitude of reserves affected by such withholding has not been significant in comparison with the total figures published by the Committee with the exception of the Prudhoe Bay Area of Alaska. We have experienced

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some temporary withholding in offshore Louisiana but it has not been significant. It should be noted that the AGA Committee would be one of the first outside bodies to receive such data when released. In any event, adequate data to prepare a reserve estimate would probably be available for the subsequent year's report.

Q. How is a reserve estimate prepared where data are withheld?

A. Reserve estimates are prepared each year for all known discoveries where there are adequate data, in the opinion of the Subcommittee, for the preparation of an estimate. Consequently, an estimate would be prepared in the normal manner unless the withheld data were of such a nature that the adequacy of data tests could not be met. In that case, an estimate would be prepared just as soon as an adequate amount of data was available and, of course, revised annually.

Q. Please answer Mr. Gooch's Question No. 14 in which he asks: "How does the Committee treat any reserves which may have been discovered by the drilling of so-called "expendable wells?"

Prepared Testimony of John C. Jacobs, Jr.

A. The question does not define an "expendable well". It is presumed that an expendable well is one drilled in the Federal offshore areas from a device other than a permanent platform. The Committee treats such reserves in the same manner as reserves discovered by any other type of well.

Subcommittees prepare estimates each year, subject to the adequacy of data limitation (which, as I have explained, is not significant) for all discoveries shown in the public records plus such additional discoveries as may have come to the attention of the Committeemen.

As has been explained, if the results of an expendable well are kept completely secret, reserves would be included just as soon as the data were made

available to persons other than the owners. One should remember that the Committee estimates are reviewed annually and that exploration is carried on on a fairly continuous basis so that the effect of withheld data is only temporary and should be minimal from the standpoint of trends indicated by the figures published by the Committee.

Q. Do you, as Chairman of the Committee on Natural Gas Reserves, know of anything to indicate that, in 1968 or 1969, data were withheld from your Subcommittee members in any unusual or greater amount than was normal in the years prior thereto?

A. With the single exception of the unusual circumstances of the Prudhoe Bay of Northern Alaska, no.

Q. Mr. Jacobs, you have emphasized throughout that your Committee was established to estimate proved reserves for the United States and that the Committee does not prepare estimates of probable reserves. In this

connection, please answer Mr. Gooch's Question No. 22 which is: "Do the data necessary for estimating 'proved reserves' provide a basis for estimating 'probable reserves'? Could you make such an estimate for the continental United States for either non-associated or total gas?"

A. The answer to both parts of the question is no. The methods of estimating probable reserves are quite different from the methods of estimating proved reserves. Consequently, both we and the Canadians have set up separate organizations to estimate potential as compared with proved reserves.

This question can be of only theoretical interest since the Potential Gas Committee has been organized and does function in producing a printed and widely-circulated bi-annual report on the probable natural gas reserves of the

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United States. Probable natural gas reserves for Canada are published annually by the Canadian Petroleum Association.

Q. Now, by way of summary, will you please specifically answer Mr. Gooch's Question No. 6, which is: "Explain the technical procedures used in making reserve estimates for new fields, new reservoirs, extensions and revisions."

A. I believe that this question has already been answered in my previous testimony. However, in order that the record may contain an answer to this particular question, I will rephrase what I have previously said and answer the question as follows:

Volumes of gas reserves are determined by geological and engineering analyses of reservoir data including

structural interpretation, well tests, core analysis, pressure production data, gas analysis, etc., available at the time the estimate is made. Recoveries of gas are estimated on the basis of formation evaluation of the reservoir rock, the producing mechanism of the reservoir and pressure production performance.

Discoveries are defined as proved reserves in newly-discovered fields and newly-discovered reservoirs in old fields. New reservoir discoveries include proved reserves in new segments of reservoirs that are separated from the previously-proved productive area by faulting, lenticularity of the reservoir, or other subsurface discontinuity. Reserves of multi-reservoir fields, included in the new field discovery category, reflect the reserves of all reservoirs proved during the discovery year of the field. New discoveries seldom are delineated or fully developed during the year of discovery. Therefore, the year-end reserves estimates of discoveries generally represent only a part of the reserves that ultimately will be assigned.

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A discovery in one year normally is delineated by the drilling of both extension and development wells during subsequent years. Drilling usually continues until the productive limits of the field or reservoirs are defined. Increases in the proved area of reservoirs result in appropriate adjustments to estimates of recoverable reserves and such changes are recorded under extensions. Changes resulting from a reduction in the estimate of the proved area are recorded under revisions.

The drilling of additional wells in a reservoir not only delineates the productive area but also provides additional basis geological and engineering data. Estimates

of porosity, interstitial water, pay thickness and other reservoir factors may be revised by new data. Analysis of the producing history of a reservoir, including production of oil, gas and water, and pressure performance results in more accurate concepts concerning the producing mechanism, recovery efficiency and the performance of the reservoir. The composite of this new and improved information will yield more precise estimates of the ultimate recoveries and remaining reserves and result in revisions to previous estimates. Changes in reserve estimates brought about by the application of cycling or other recovery techniques are included in the revision to reserves. Also, changes in reserves resulting from a reduction in the estimate of the proved area are included in revisions.

No particular procedure is designated by the Committee to be followed by Committeemen in preparing the reserve estimate for a particular field. Each man preparing a field estimate selects the methods best suited for that particular field.

Q. Please answer Mr. Gooch's Question No. 10, which is: "How are any disagreements within a Subcommittee or the Committee resolved?"

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A. By discussion. As has been pointed out, all reserve estimates are subject to discussion by the entire Subcommittee prior to acceptance and all estimates are reviewed each year. This annual review which, as time progresses, is based more and more upon production history which is the most accurate determinant of reserves, results in a continuing correction of any errors in past estimates.

Prepared Testimony of John C. Jacobs, Jr.

Q. Will you now answer Mr. Gooch's Question No. 11, reading as follows: "Do the Subcommittees evaluate each reservoir or field each year for extensions and revisions" If not, what policy is followed?"

A. My answer is emphatically "yes", and herein lies one of the great strengths of the Committee procedures.

Q. Mr. Jacobs, there has been a dramatic and remarkable shift in the reserve situation in the 1968 and 1969 reports. Were the instructions to all Subcommittee and Committee members in any way changed in 1968 and 1969 from the instructions given in prior years?

A. No.

Q. Was there any change in the procedures used by the Committee?

A. No.

Q. Are there any discoveries known to the Committee not included in the 1968 and 1969 reports?

A. As I have said before, with the exception of the Prudhoe Bay area of Northern Alaska, there are none.

Q. Mr. Jacobs, the 1969 report for the first time shows a negative revision and this of major import. Will you please explain what caused this adjustment to the reserves?

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A. I regret that I am unable to provide such an explanation in other than the arithmetical sense of saying that there were more downward revisions of prior field reserve figures than there were upward revisions. These revisions were dictated by data made available from the year's drilling and producing activities, and were predominantly of the pressure-production history type. Generally speaking, pressure-production data give a much more accurate measure of reserves than do the so-called volumetric studies. Whereas in the pressure-

production approach one calculates the size of a reservoir from a measured pressure charge corresponding to a measured quantity of production, in the volumetric approach the engineer must estimate the relative amounts of rock, water and gas in the entire reservoir from tests made on a little piece of rock—called a core —which usually is four to five inches in diameter and no longer than the reservoir is thick.

One must keep in mind that our Committee is only charged with the estimation of proved reserves as we find them to exist at the end of each year. We make no effort to explore the reasons why more reserves are not found or developed. This is a matter for those who decide when and where leases are to be purchased and wells are to be drilled. Because of our status as a technical committe reporting only its findings, we have never considered it appropriate or necessary to comment upon year-to-year variations in revisions or reserves added, nor to draw any conclusions therefrom.

Q. As a means of providing an estimate of proved reserves for the United States, would you comment on the relative strengths and weaknesses of the method which is embodied in the organization and activities of the American Gas Association Committee on Natural Gas Reserves?

A. The American Gas Association Committee on Natural Gas Reserves embodies several strengths or advantages which could not be equaled by any other conceivable arrangement for producing a proved reserve figure for the United States.

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First, the real strength of the Committee on Natural Gas Reserves, as with any organization, lies in the

people who do the work. The Committee has ready access to the entire reservoir engineering profession of the United States. Not only does this mean that the most able men in terms of experience, judgment and technical ability are available, but it also means that men who have the advantage of being daily active in the energy business in America are available to give the benefit of this experience to the Committee.

Another advantage of our Committee organization lies in its ready and comprehensive access to data because our Committeemen are active and respected members of the reservoir engineering fraternity and because they are also actively employed in one phase or another of providing energy for our nation. They are in the best possible position to know which data are available and to gather access to such data. Committee organization and the standards for maintaining confidentiality mean that this group has access to more confidential data than would otherwise be available, and that, when data which have been withheld are released, such data will be released to this group first.

Another advantage lies in the continuity of operations of the American Gas Association group. For 24 years, the public has been supplied with a series of data without change in the methods or standards by which these results are developed. This contribution should represent one of the most consistent and reliable series of energy statistics available anywhere. Another aspect of the advantage of continuity lies in the continuing annual review of all reserve estimates which gives greater accuracy as time progresses.

Another advantage of the American Gas Association arrangement is that all these reserve figures are made available to the public at no cost.

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In preparing the proved gas reserve estimates for the United States, there are at least two problems which must be answered from an organizational

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standpoint. One of these is the possibility that a special interest group will obtain control of the organization and bend the results in a direction which it thinks favorable. A second problem lies in access to data in which the owner has such a proprietary interest that the data are confidential. As compared with other possible methods of producing a proved reserve estimate for the United States, the Committee on Natural Gas Reserves has no weaknesses in these regards.

The method by which the Committee and its Subcommittees are organized and operated, and the diversity of employment of the Committee members, rule out any possibility of any special interest group—be it management, stockholders, promotors, a group with special economic interests, a group representing government or a group representing regional political interests—being able to influence the Committee's results. To the best of my knowledge and belief, any such special influencing of results is completely absent. In fact, my personal knowledge of the men who make up the Committee and Subcommittees indicates that these men are mature professional engineers who would resent dictation from any source.

In so far as having access to data which have not been made public is concerned, my testimony has covered the organizational set-up which has been built into the American Gas Association Committee to maximize access to such data. No alternative method of estimating

reserves is known which would have a greater access to such data than does the Committee or which would have an earlier access to such data.

Q. Would you comment on some of the alternative methods of producing an estimate of proved natural gas reserves for the United States?

A. Only two readily suggest themselves. One might engage a consulting firm to produce such an estimate or one might require all available data to

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be sent to a central computing center where it would be processed on the basis of fixed rules.

As compared with the American Gas Association Committee, the use of a consulting firm would have the disadvantage of reduced access to data, of estimates based on the judgment of a few engineers rather than on many, each an expert in his own area, and of requiring that a substantial fee be paid to the consulting firm by somebody.

As compared with the Committee procedures, the use of a computing center would have the disadvantages of limited access to data, of no method for scrutinizing the data which are fed into the machine, and of no judgment by experienced engineers as to the methods used in computing each field reserve figure. The use of a computing center would have the added disadvantage of requiring an additional social cost as compared with the use of the American Gas Association Committee. In fact, establishing such a computer center would produce a classic example of that part of computer results which is characterized by the phrase "garbage in, garbage out."

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Q. Taking into account all aspects of the problem of producing a proved gas reserve figure for the United States, what is your opinion of the results produced by the American Gas Association Committee on Natural Gas Reserves?

A. My study of the problem has convinced me that the reserve estimates produced by the Committee on Natural Gas Reserves are the most accurate and reliable possible.

Q. Mr. Jacobs, do you have anything to add to your testimony?

A. I should like to add an invitation to all of those persons who use the American Gas Association Committee on Natural Gas Reserves' reports to

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forward any questions which they have about the reports and their contents either to me in Houston or to the Secretary of the Committee at the American Gas Association offices. We will do our utmost, within the confidentiality of data limits under which we operate, to be cooperative in providing ready and meaningful answers to all questions which are submitted.

Prepared Testimony of John G. Winger

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL POWER COMMISSION

AREA RATE PROCEEDING
(SOUTHERN LOUISIANA)
Docket No. AR69-1

PREPARED TESTIMONY OF JOHN G. WINGER

Q. Please state your name, address and business position.

A. My name is John G. Winger. I am a vice president of The Chase Manhattan Bank in New York and am manager of the Bank's Energy Economics Division. I have been associated with the Bank as an energy economist for the past 20 years.

Q. Please state your education and business background other than with The Chase Manhattan Bank.

A. I was graduated from the University of North Dakota in 1941 and, following service in the U.S. Navy during World War II, I was employed as a petroleum economist from 1946 to 1950 by the Cities Service Oil Co., New York.

Q. Are you a member of any professional societies?

A. I am a member of The National Petroleum Council; The American Petroleum Institute; the Independent Petroleum Association of America; and The Advisory Board of The Oil and Gas Center Southwestern Legal Foundation, Dallas.

Q. Please describe the activities of the Energy Economics Division of The Chase Manhattan Bank.

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A. The Energy Economic Division of The Chase Manhattan Bank is one of three divisions that comprise the

Bank's Energy Group. The other two are the Petroleum Division and the Public Utilities Division. The activities of the Energy Economics Division extend back to 1936 and they are carried on for several purposes. First, the Division provides full time counseling service to the Bank's worldwide lending and investment areas on all matters relating to the various energy industries: coal, oil, gas, electricity and nuclear. In addition, the Division serves as a consultant to any and all customers of the Bank who seek information pertaining to energy matters. The Division also provides specialized information, when requested, to all areas of government and education. To provide a broad and detailed knowledge base for these activities, a large staff of energy economists and analysts is continuously involved in detailed studies relating to energy on a worldwide basis. In addition to its own staff, the Division also utilizes the services of petroleum engineers, chemical engineers, and financial specialists located in the Petroleum and Public Utilities Divisions. For many years, the Division has conducted detailed studies of the financial performance of the oil and gas industry on a worldwide basis. The companies involved in these surveys constitute a base that is much larger than that which is utilized for many commonly-used economic indicators. The Division releases regularly several publications based upon its studies. Because the Bank serves customers from all segments of

the economy, the Division's conclusions and consulting service must be as free of bias as is humanly possible.

Q. What will be the scope of your testimony in this proceeding?

A. I have been asked to give my analysis of the reasons for the present gas shortage and my recommendations for correcting this situation. I believe that it will first be necessary to review the historical background of pricing gas and other hydrocarbon products, after which I will be able to give my conclusions about the present status of investment in the industry and the need for future expenditures. This need, of course, is dependent, in part, upon consideration of alternative sources of supply. I will review these alternatives before starting my recommendations.

Q. Mr. Winger, in your opinion, based on your knowledge and experience, is the country facing a natural gas shortage?

A. The United States is on the threshold of a shortage of natural gas that promises to become critical unless corrective actions are taken. It is not a shortage that has developed suddenly—the first signs became apparent about 15 years ago. But they were recognized by so few that virtually nothing was done to prevent the situation that exists now.

It appears certain that conditions will get worse before they can possibly improve. And, if there is to be any improvement, positive actions must be initiated as early as possible. Before that can happen, however, there must exist the broadest

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possible understanding of the true nature of the problem—by all segments of the oil and gas industry, by the various levels of government, and by consumers.

Q. What is the cause of the present gas shortage?

A. A dispassionate and comprehensive study of the past will reveal that, rather than a single cause, a combination of factors was involved. But, to varying degrees,

they all influence the key problem—the formation of capital. It was the industry's over-all relative inability to generate enough capital that has led to a shortage not only of natural gas, but liquid petroleum as well.

The lingering effects of the great depression in the early thirties, a business recession in 1938, and large scale discoveries of new reserves together cause the price of domestic crude oil to be severely depressed immediately prior to World War II. And it was frozen at that level by the price controls imposed during the war. With the lifting of the restrictions in mid-1946, the price of domestic crude oil began to advance. Between early 1946 and early 1957, the average price rose from $1.22 to $3.17 per barrel. At the same time, the demand for domestic crude oil was growing at a healthy rate of 4.3 percent a year. Together, these developments caused the wellhead value of the nation's petroleum production to increase nearly fourfold. As a result, the industry had a rapidly-expanding financial base from which to generate capital funds. And it also had the incentive to reinvest those funds in the search for more domestic oil and gas.

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Immediately following World War II, the industry was spending 1.5 billion dollars a year for such exploration and development. The major companies as one group and the independent producers as another were each spending almost identical amounts. And, for the next decade, both groups progressively increased their rate of spending. By 1957, each group had more than trebled its annual outlay, and industrywide spending was in excess of 5 billion dollars.

But, in the following year, the industry reduced its outlay by nearly a billion dollars. And, for the next

decade, the annual rate of spending for domestic exploration and development remained on a plateau of 4.25 billion dollars a year. Although both majors and independents had spent nearly identical amounts in the first decade following World War II, the pattern of spending changed to a marked degree after 1957. Independent producers, as a group, progressively reduced their annual outlay and currently they are spending only half as much as in the peak year of 1957. Following a sharp reduction in 1958, major companies gradually increased their spending. But the rate of increase was much smaller than in the previous decade and was only large enough to offset the decline in spending by the independents.

Q. Will you please discuss the factors responsible for the change in the industry's attitude with respect to capital spending.

A. Various factors were responsible for this change. First, I should note that the search for domestic crude

oil provided the major incentive for capital expenditures. After 1957, there was no further increase in the average price of such crude oil. In fact, it declined progressively from $3.17 per barrel in 1957 to $2.86 per barrel in 1965. Since then it has recovered gradually, but the current price of $3.10 per barrel is still below the level of 13 years ago. The weakening of the price for domestic crude oil reflects a sharp contraction in the growth of demand for such crude oil. In contrast with an average growth of 4.3 percent a year in the first decade following World War II, the expansion over the next 6 years averaged only 0.3 percent a year. And for all of the period from 1956 through 1969, the demand

for such crude oil grew at no more than 2.0 percent a year. As a result of these changes, the annual growth of wellhead value was much slower after 1956. And there was also an adverse financial impact on the industry's operations beyond the wellhead.

The slowdown in the growth of domestic crude oil demand can be traced directly to the impact of two competitive forces—natural gas and imported oil. Of the two, the gas impact was by far the most significant. Between 1956 and 1962, the demand for domestic crude oil rose by only 140 thousand barrels per day. But in the same period, the market for natural gas, expressed in oil equivalent, increased by 2.0 million barrels per day—more than fourteen times as much. The growth of imported oil in that time span amounted to 646 thousand barrels per day—nearly five times as large as the crude oil expansion. For the entire period ranging from 1956 through 1969, the market for domestic crude oil rose by

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2.1 million barrels per day compared with an increase of 5.2 million barrels per day equivalent for natural gas. Imports of foreign oil in that period rose by 1.7 million barrels per day. Of the over-all market expansion for petroleum hydrocarbons between 1956 and 1969, domestic crude oil was able to capture no more than 21 percent compared with 53 percent for natural gas and 17 percent for imported oil. Natural gas liquids supplied the balance.

Obviously, domestic crude oil, natural gas and imported oil were all competing in much of the energy market for the same customers. And the inability of domestic crude oil to compete more successfully was a major impediment to the generation of capital funds.

Q. But did not the increase in gas sales provide sufficient incentive for capital investment in drilling?

A. No, it did not provide the required economic incentive. Between 1956 and 1969, the industry produced and sold 205 trillion cubic feet of natural gas. The accumulated revenue generated by this activity amounted to 23 billion dollars. Although it is not possible to make a completely practical and clear-cut industrywide segregation of all the joint costs associated with the finding and development of oil and gas reserves, we know that for every dollar of expenditure between 1956 and 1969 the petroleum industry has found equal amounts of liquid and gas hydrocarbons. And, if expenditures were prorated accordingly, the portion allocated to

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gas would amount to more than 31 billion dollars. On that basis, the expenditures would exceed the revenue received by approximately 8 billion dollars. The addition of operating costs would raise the deficit to 16 billion dollars.

Q. Why has the industry not priced its products in a way that would eliminate the deficit?

A. Under actual circumstances, the industry has not been free to allocate joint costs according to the economic realities of the energy market. This has caused an underpricing of gas. As a result, much of the burden of cost had to be recovered in the price of domestic crude oil. Consequently, the products refined from that crude oil were unable to compete in terms of price with either natural gas or imported oil throughout most of the nationwide energy market. And the industry's potential for generation capital funds beyond the wellhead, therefore, was severely limited. As indicated earlier, well over

half of the market expansion for petroleum hydrocarbons since 1956 has been natural gas. And a thorough end-use analysis of the energy market indicates that much of that growth would have gone to liquid petroleum in the absence of gas, obviously with more favorable financial results.

Q. What action has the industry taken with respect to the use of imported oil, and what impact have these actions had on the generation of capital?

A. Most major oil companies are refineries on balance—in other words, they refine and market substantially more oil than

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they are able to produce from their own properties. To supplement their own production, several of the majors began many years ago to substitute lower-cost foreign oil for the crude oil purchased from independents. By the mid-fifties, all the majors were encountering severe competition from rapidly-expanding volumes of natural gas delivered to consumers at a price much below the minimum level that could be justified for refined oil products. And that situation led to intensified efforts to substitute imported oil for domestic production. And it also led to the decision on the part of some companies to withdraw from markets where they were unable to compete effectively. These developments, of course, had an adverse impact on the generation of capital funds and the incentive to invest in the search for more domestic petroleum reserves.

Q. Would you trace more specifically the factors which have influenced the pricing of gas.

A. In the beginning, natural gas was truly a by-product. And the industry priced it accordingly. But gas emerged from its by-product status long ago and has

become a premium form of energy. Properly, the industry should have priced gas in accordance with its changed value and the competitive realities of the energy market. But the industry failed to recognize the changed value at first and later, under regulation, it has not been free to set prices.

In the early days of the petroleum industry, gasoline was

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also a by-product. Indeed, it had absolutely no monetary value and presented a difficult problem of waste disposal. But, with the invention of the automobile, gasoline became a valuable petroleum product. And the industry was completely free to price it accordingly. As a result, the sale of gasoline now contributes as much as 60 cents of the total revenue dollar derived from the overall sale of petroleum hydrocarbons. But the sale of natural gas contributes less than 5 cents of such revenue dollar—even though the gas represents nearly twice as much petroleum hydrocarbon energy.

Like gasoline, heavy residual oil was also a by-product of the refining process in the earlier years of the industry. Potentially, there was a very large market for residual oil as a boiler fuel. But competition has prevented the industry from ever realizing a price for residual oil sufficient to cover the cost of the domestic crude oil from which it was refined. Therefore, the industry has constantly sought to reduce the production of residual oil from domestic crude through changes in refining technology. And now, as much as two-thirds of the market for this product must be supplied with imports.

To a significant degree, the developments in respect to residual oil and natural gas have been similar—neither source of energy has ever contributed impor-

tantly to the industry's generation of capital, and consequently both are now in short supply domestically.

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Q. What effect has this pricing history had on the discovery of new reserves?

A. As might logically be expected, there is a close relationship between the amount of money invested in the search for petroleum and the amount of new reserves actually found. For the last quarter of a century, that relationship has remained fairly consistent. In the first 12 years following World War II, the industry was able to find approximately one barrel of liquid hydrocarbons and a slightly smaller quantity of gas energy per dollar spent. As noted earlier, the industry increased its spending year after year in that period. And it found enough new oil and gas to supply market requirements and maintain a satisfactory level of proven reserves. But for the reasons cited earlier, the industry reduced its level of spending sharply after 1957. Since then, it has spent a total of 53 billion dollars and it has found three quarters of a barrel of liquids and an identical amount of gas energy for each dollar spent.

The additions to domestic reserves in the second 12 years following World War II were far short of needs. And the ratio of domestic reserves to consumption declined sharply. For the past 10 years, the industry has actually found less crude oil and other liquids than the nation has consumed. And for the last 2 years it has found less gas than the market required.

Obviously, neither oil nor gas markets can be served on a hand-to-mouth basis—reserves must expand in a reasonable

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proportion to the growth of markets. And if the trends of the recent past continue, market growth will have to be curbed—unless alternate sources of supply can be developed.

Q. In your opinion, what level of capital spending is required by the industry?

A. In terms of the results achieved in the past, the oil and gas industry would have had to spend 90 billion dollars—or 37 billion more than it actually did—if it had tried to prevent the decline of reserve ratios that has occurred over the past 12 years. And, obviously, it will have to invest a great deal more in the future. Reserve ratios are now at minimal levels. And if the industry is to hold them at those levels and satisfy full market requirements without resorting to proportionately higher imports, it will have to spend approximately 150 billion dollars between now and 1985. That would require an annual outlay more than twice as large as the current level of spending.

Q. In your opinion, will the industry be able to invest the amounts of capital required?

A. Under the present circumstances, and absent additional incentives, there is no basis for thinking that the industry would be able to invest that much money. The industry is international in character. And, of all the capital spending throughout the Free World, American companies alone account for 70 percent. Of the spending devoted to the search for new reserves, they are responsible for as much as 85 percent. Progressively over the

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past decade, the international petroleum industry has experienced a declining ability to generate sufficient

funds from operations for all its financial requirements. And, therefore, it has been forced to use the capital markets to a greater extent. Although borrowed capital permits certain advantages in timing, it all must eventually be repaid with funds generated from operations, of course. As a result of these developments, the industry has become increasingly selective in terms of where and how its available capital is employed. The decision is influenced by the combination of geologic, economic, and political circumstances encountered in each area of potential investment. If one or more of these factors is unfavorable, the industry will be likely to use its capital resources elsewhere. And recent history has demonstrated repeatedly that capital will quickly take flight when conditions become unfavorable.

Q. Will you please discuss the conditions you have in mind and state why they affect future investment in gas exploration?

A. The manner in which the price of natural gas has been regulated in the United States is an example of an unfavorable factor. Another example was the lowering of the depletion allowance last year. As a result of that action, the industry's ability to recover capital funds was reduced and the incentive to reinvest was damaged further. Still another example is the recent recommendation by the President's Task Force Committee that the price of domestic crude oil be forced down by increasing the volume of imports.

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Without any additional economic incentive, there is little likelihood that the industry will increase its rate of spending for the purpose of finding new domestic oil and gas reserves. The entire economy is experiencing a

shortage of capital that is destined to last for many years to come. And for that reason, independent producers will have abundant opportunities to continue to shift their capital into other areas of economic endeavor. Major companies will also have reasons for diversifying. And, in addition, they will have an increasing incentive to utilize proportionately more capital outside the United States where the market growth potential is much greater.

Q. You have previously stated what you believe to be the required levels of spending in order to maintain present minimum reserve ratios. In your opinion, what would be the consequences if the industry were to spend lesser amounts of capital?

A. If the annual spending rate of recent years continues until 1985, the outlay for that period will total 75 billion dollars. And if the industry continues to find the same amount of oil and gas reserves per dollar invested as in the past, its discoveries will be much too small relative to needs. With the ratios of reserves to production at minimal levels, the annual rates of production will fall increasingly short of market requirements. By 1985, at current levels of spending, domestic sources could be expected to provide only half of the requirements for oil and no more than 55 percent of the market needs for natural gas.

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Conceivably, the United States might be able to import half of its oil requirements. But there is no reasonable possibility that such deficit of gas supply could be filled with imports of gas.

The situation as to both oil and gas could become even worse if the proposal to reduce the price of crude

oil by encouraging the flow of imported oil were implemented. In that event, the domestic industry could be expected to curtail severely the amount of money it spends on the search for more domestic petroleum. It would continue to spend for the purpose of protecting important investments already made. But it would be unlikely to initiate new programs. At the most, the annual outlay would not be likely to exceed 2 billion dollars. And at that rate, domestic sources would be unable to satisfy more than one third of the nation's needs for both oil and gas by 1985. It would be a tragic mistake, indeed, if the nation were led into that predicament.

Stated another way, our studies relative to the nation's future energy requirements indicate the market for natural gas will amount to 90 billion cubic feet a day in 1985; and, based upon a continuation of the current spending rate, the domestic industry would be able to supply no more than 50 billion cubic feet a day by that time, including the supply expected from Alaska.

Q. Have you given consideration to the part which Canadian gas, LNG, and coal gasification can play in making up any such gas

[1,467]

deficit resulting from current levels of spending?

A. Yes.

Q. What do you consider to be the most promising alternative source of supply?

A. Imports from Canada rank as the most likely alternative. Geologic prospects for finding additional gas reserves in Canada are good. But, as in the United States, they will not be found without an increase in the rate of exploration and development spending.

American companies account for 70 percent of the spending in Canada and they are influenced by many of the same forces that apply in the United States. A decision to increase the level of spending in Canada conceivably might be relocated in a reduction of comparable size in the United States, since for the most part common capital source would be involved.

Based upon current reserves and a realistic projection of spending over the next 15 years, Canada could be expected to export approximately 5 billion cubic feet of gas a day to the United States by 1985. That assumes, of course, that Canada would be willing to release that much gas, and further that no limitation is imposed upon the involvement of foreign capital. The cost of future supplies of Canadian gas is likely to be substantially greater than the current price in the areas it would serve. The wellhead price of Canadian gas has been influenced by prices in the United States in the past. But that influence is likely to wane in the future, as this nation's dependence upon Canadian gas

increases. And the negotiated price, therefore, is expected to advance. In addition, the greater distances involved in reaching the more remote areas where new gas reserves are likely to be located will add to transportation costs.

Clearly, 5 billion cubic feet a day will not go far toward filling a deficit of 40 billion cubic feet.

Q. Will you please discuss potential LNG imports?

A. Importing gas in liquefied form by tanker is a growing possibility. Reserves in Eastern Hemisphere sources are believed to be large, but measurements of the caliber utilized in the United States are not avail-

able, and not much is actually known about their true size. Several of the potential sources of LNG supply have frequently been the scene of strife and turmoil. And, for that reason, they are uncertain sources of supply and therefore are relatively unattractive from the standpoint of capital investment. Changes in government are not always peaceful transitions and new governments are not necessarily bound by agreements made by former governments. There is also the problem of maritime strife of one form or another which in the past has tied up shipping frequently and for lengthy periods. An LNG operation will be highly capital intensive. Current estimates indicate at least one billion dollars of capital investment will be required to provide liquefaction facilities, storage, pipelines, and tankers sufficient to deliver one billion cubic feet of gas a day.

What the delivered cost of LNG will be is highly uncertain.

[1,469]

The current feasibility of an LNG operation is dependent upon an extremely low price for the gas at the wellhead. And there is no reasonable basis for believing that any foreign government would be content with such a low price for long. An examination of their past record in respect to oil operation should remove any doubts on that score. It seems quite likely that LNG will be expensive and its availability will probably be limited to coastal markets. Because of all the risks involved and the massive capital requirements, it appears highly improbable that as much as 10 billion cubic feet per day of LNG will be delivered to market by 1985.

Q. What about coal gasification?

A. Coal gasification is another possible alternative. Reserves of coal are adequate. But heavy capital require-

ments and complicated technical problems that must be overcome are major impediments to large-scale rapid development. And it seems doubtful that more than 3 billion feet of gas a day will be available in 1985 from this source. Moreover, the gas derived from coal will surely be much more expensive than current sources.

Q. Then, in the aggregate, will these alternatives eliminate the current and impending gas shortage?

A. The maximum amount of gas that conceivably might be supplied from all the potential alternate sources by 1985 will fill less than half of the above-stated deficit of 40 billion cubic feet a day. And all of the alternate supply will be much more expensive than the current cost of gas from conventional domestic

[1,470]

sources. The capital requirements will be very large and, except in Canada, little of the money will be supplied by the domestic petroleum industry. Unless some additional form of relief can be found, the nation is faced with a growing shortage of natural gas from this point forward.

Q. What are your recommendations for relieving the present gas shortage and for preventing an even larger shortage in the future?

A. As I have demonstrated in the foregoing discussion, the problem has evolved from a situation that is financially unsound. And that situation will have to be corrected, if the problem is to be alleviated.

The petroleum industry is capital intensive. And if it is to function effectively, the industry must be able to achieve sufficient capital formation. And it also must have sufficient reason to reinvest rather than employ capital elsewhere. If those conditions are to be met, the

industry must be free to price all its hydrocarbons in terms of the risks involved, the costs incurred and the competitive conditions encountered in the energy markets.

Geologic studies suggest the existence in the earth of large amounts of gas remaining to be discovered. But, obviously, if it is to be found in the quantities necessary to serve expanding market needs, much more money must be devoted to the search. Beginning as soon as possible, the annual outlay for both oil and gas exploration should be expanded by at least 2 billion dollars

[1,471]

and thereafter it should increase progressively each year to a level of 13 billion by 1985. Clearly, if the industry is to spend that amount of money, it must have the ability to generate it. And if that goal is to be achieved, it will need to receive higher prices for oil and gas alike.

An increase of 1 cent per thousand cubic feet of gas would create approximately 90 million dollars of revenue after taxes that potentially might be applied to the search. An equivalent increase of 5.6 cents per barrel for crude oil would make available another 150 million dollars. Obviously, increases of that size would fall far short of generating the additional 2 billion dollars that is necessary. And, therefore, substantially larger increases will be required. An advance of 1 cent per gallon in the price of gasoline would create a larger amount of money—approximately 500 million dollars, after taxes. But we should be mindful that every recent industry attempt to raise gasoline prices has precipitated a great deal of political protest. And the industry, therefore, has become extremely gun shy.

Q. Will this mean an increase in costs to the consumer?

A. Yes, but not a large increase relative to the rising cost of other essentials.

The price advances in oil and gas that have occurred in the past have been extremely modest and each can be demonstrated to be a great bargain. Although a consumer's standard of living is measured by the sum of everything he acquires, not all of his

[1,472]

purchases can be considered necessary, of course. But there are some that are highly essential, and if they became unavailable, great hardship would result. Food, clothing, transportation, heat, and medical care all fall in that category. And government, to a degree, is also absolutely essential. For many years, the cost of all these essentials has been rising. The amount of the increase between 1950 and 1969 is measured and compared in the following table for representative examples. Gasoline is the most commonly-used transportation fuel. And nearly all the needs for heating are satisfied with natural gas and heating oil. The combined tax payments to all levels of government provide the most meaningful measure of the cost of government.

Consumer Prices
1969 vs. 1950

	Percent Increase
Natural Gas	18
Gasoline	19
Heating Oil *	28
Meat	30
Rent	50
All Commodities	53
Footwear *	55
Bread	61
Milk	68
Medical Care	111
Per Capita Taxes	240

* Wholesale (Retail unavailable)

The changes revealed in the table are also traced historically in the panel of charts attached as Exhibit 20. To avoid distortion, each of the charts is drawn precisely to the same scale and all the trend lines can be compared directly with one another.

[1,473]

As the table indicates, the price rise for the three petroleum products is smaller than for the other essentials. And the rise for natural gas is the smallest of all. The financial impact of the price increases for petroleum has been relatively small. For the average gas-heated dwelling, the cost in 1969 was $92—only $13 more than in 1950. For an oil heated home, the cost was $280—or $60 more than in 1950. And, for the average privately-owned automobile, the cost of gasoline, excluding state and federal excise taxes, was $150—only $24 more than in 1950. For an average family with a gas heated home and one car, the combined cost of gas and gasoline was $37 more per year in 1969 than in 1950.

And for the family with an oil heated home, the combined increase amounted to $84. But whether the family used gas or oil heat, the combined increase in its annual outlay for petroleum products represented only a small fraction of the additional amounts it had to pay for other essentials. Over-all personnal consumption expenditures per family were $6,600 greater in 1969 than in 1950.

Because gasoline, heating oil, and milk are all liquids, their consumer prices can be compared on a common-unit basis. Although the natural gas used for heating is not sold to consumers in liquid form, it can readily be expressed in liquid equivalent for comparative purposes. The following table shows the changes that have occurred since 1950:

[1,474]

Consumer Prices

	1969	1950	Increase
	Cents Per Quart		
Natural Gas	3.0	2.5	0.5
Heating Oil	4.4	3.4	1.0
Gasoline	5.9	5.0	0.9
Milk	33.5	19.9	13.6

The figures speak for themselves. And, in my opinion, if the price of milk had been restrained to the extent the price of gas was, there would doubtless be a shortage of milk today, too.

As indicated in the first of the two tables, the cost of government has soared. Per capita tax payments to all levels of government have risen from $469 in 1950 to approximately $1,600 in 1969. That change exerted a strong upward push to both wages and prices. And in

that period, wages and salaries per wage earner actually rose by 160 percent. Obviously, prices had to respond.

In this kind of environment, it is unrealistic to think that the price of natural gas and other petroleum products can be restrained without leading to shortages.

Q. Do you believe that an increase in the price of gas will be in the public interest?

A. Between now and 1985, the nation's requirements for all sources of primary energy are expected to increase by 75 percent. And among these sources, natural gas ranks as a premium form of energy for use in the home, in commerce, and in industry. From the standpoint of dealing with the problems of air pollution, natural gas is particularly valuable. Natural gas has been selling

[1,475]

at bargain prices. And it would be unfortunate indeed if, for the want of a modest increase in price, millions of consumers were denied the kind of energy they want and need. It cannot be denied that an additional economic incentive is necessary. Our democratic society has not failed to respond to the need for additional economic incentives before—and it is not likely to this time either, if given the opportunity.

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[1,613]

the AAPG.

I also serve as an Area Chairman on the Potential Gas Committee. My area is designed "J" by the Committee and consists of Southeast New Mexico, Railroad Commission District Nos. 7-C, 8, 8-A, and 10 in Texas, the State of Kansas and most of Oklahoma. Estimates of the potential but undiscovered supplies of natural gas are made and published every two years by this committee.

Q. What is the subject matter of your testimony and exhibits in this proceeding?

A. My testimony and exhibits are directed to the following points:

(1) It is my understanding that one of the principal issues in this proceeding is the adequacy of future supply of natural gas in this country. It is my conclusion that if optimal supplies of gas needed to meet future demands are to be available, the bulk of these supplies will be found only as a result of a directed and separate search for gas reservoirs. It therefore follows that if adequate supplies of natural gas are to be forthcoming in this country, the price for gas must be attractive enough to stimulate the separate search for natural gas reservoirs.

(2) The incentive price for increasing gas exploration must be established under circumstances which reflect the unavoidable lead time between the commencement of exploration

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time, except in limited areas, we had not attempted to record how much money we were spending in exploration separately for gas and for oil. Phillips' management was troubled that we did not know what separate amounts we were spending in looking for gas and in looking for oil. As a result of this interest considerable attention was given to this matter with a view to the possibility of separately recording the exploratory costs as much as possible.

As we went forward, we realized more and more that many of the costs of exploration were made directly in the search for gas reservoirs or for oil reservoirs. We knew that in certain areas and at certain depths our exploration had to be for gas reservoirs because that was all we were finding or expected to find.

In certain other areas, our exploration was for oil reservoirs because that was all we were finding or expected to find in those areas. In still other areas, where both oil and gas reservoirs occur, we found that on the basis of our geological information we could in many cases state in advance whether the objective of a particular exploratory expenditure was the search for gas reservoirs or for oil reservoirs.

Q. Was this type of knowledge reflected in Phillips' record keeping?

A. Yes, with the advice of the Exploration Division,

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[1,632]

PREPARED DIRECT TESTIMONY OF EZRA SOLOMON

Q. Please state your name and address.

A. My name is Ezra Solomon and I reside in Stanford, California.

Q. What is your present occupation?

A. I am Dean Witter Professor of Finance, Graduate School of Business, Stanford University. I do both teaching and research in the field of financial management and managerial economics. I also engage in a wide range of consulting work.

Q. Please describe your education.

A. I graduated with a First Class Honors Degree in Economics from the University of Rangoon, Burma, in 1940. I did graduate study at the University of Chicago from 1947 to 1950, where I received my degree of Doctor of Philosophy in finance.

Q. What has been your work experience?

A. I was tutor in the Department of Ecnomics, University of Rangoon in 1940 and 1941. I was a Lieutenant, Burma Division, Royal Navy, from 1942 to 1947. I was on the faculty of the Graduate School of Business, University of Chicago, from 1948 to 1961, as Professor of Finance from 1957 to 1961. I have served as Visiting Professor at the Massachusetts Institute of Technology and at the University of North Carolina. I have lectured abroad in England, Sweden, Denmark, Italy, Switzerland, India and most countries in Latin America. From 1953 to 1957,

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[1,692]

Q. What does this calculation show?

A. As of December 31, 1968, Superior's long-term debt contained two elements. $35.4 million of 3-3/4th percent debentures and $47.2 million of long-term notes (maturing in over one year) which carry a rate set equal to the commercial bank prime rate plus 1/4th percentage point.

The prime rate (since June 9, 1969) is 8½ percent, giving us a nominal cost on this portion of Superior's debt of 8.75 percent.

However, most bank debt today carries a requirement that the borrower hold minimum compensating balances at the

[1,693]

bank from which it borrows. This requirement has become formal in recent years and the average requirement is 20 percent. The fact that such cash balances have to be held continuously makes the effective cost of bank borrowing higher than the nominal cost. In this case, Superior's effective cost on its bank loan would be not 8.75 percent, but almost 11 percent per annum.

The weighted average of the two rates, 3.75 percent on debentures and 11.00 percent on notes, gives an overall interest cost of 8.90 percent on Superior's $82.6 million long-term debt. I will therefore use this rate as the representative rate on the long-term debt-financed fraction of total capitalization.

Q. What overall book rate of return would this yield?

A. My conclusion on the equity component is that the fair rate of return on beginning of year book equity is 16.0-17.0 percent for oil and gas exploration and produc-

tion. Since the equity component of total capitalization is 90 percent and the long-term debt component is 10 percent, the book rate (imbedded cost basis) on debt of 8.9 percent would yield a weighted average overall rate of between:

$$(.16 \times .9) + (.089 \times .1) = 15.3 \text{ percent.}$$

and $$(.17 \times .9) + (.089 \times .1 = 16.2 \text{ percent.}$$

I would conclude therefore that the fair book rate of return to be applied to a net book value rate lies in

this range. This range is also correctly applicable to the theoretical proxy for such a rate base used in the "new gas" cost computations made in earlier area rate decisions.

Q. Dr. Solomon, does this conclude your testimony on the fair book rate of return which independent producers of natural gas should be permitted to earn?

A. Yes, it does.

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[1,696]

TESTIMONY OF J. RHOADS FOSTER

Q. What is your name and address?

A. My name is J. Rhoads Foster. I am President of Foster Associates, Inc., a consulting firm located at 1101 Seventeenth Street, Northwest, Washington, D. C.

Q. Is a statement of your experience with regulatory problems to be found in Docket AR61-2?

A. Yes.

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[1,709]

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When the price of gas is held below the competitive level, so that supply becomes deficient relative to demand, the interstate consumers who are the principal victims of the shortage must turn to more expensive alternative sources of energy. The prices of the alternatives are higher than the regulated price of gas from domestic sources. In these circumstances, regulation has failed to reach its goals and discriminates against, among others, the consumers who pay the higher prices for the supplemental sources of energy. For those consumers who continue to use domestic natural gas, higher prices may be exepcted as a result of declining load factors of the pipelines serving them.

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Q. Do you have any comments on the proposition that

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investment decision-making by gas producers looks to future profitability?

A. Yes. Incentive for investment is provided by prospective profits commensurate with the returns available from alternative investments. The objective of capital budgeting by the managers of petroleum companies is to commit available funds to the most promising among the wide range of investment opportunities within their reach. Competition for available capital is always intense. Investment in gas exploration, development, and production is dependent upon choices among the many available projects on the basis of relative prospective profit. Exploratory expenditures will not be made unless, taking account of the load time before returns are realized, the estimated present value of the prospective earnings is equal to the present value of returns from alternative investments of corresponding risk. These characteristics of investment by the producing industry are ignored by a costing procedure based upon accounting data for a group of producers in a past period or test year.

Q. You stated that gas supply cost tends to increase with an increase in the quantity of gas to be found and developed. Please explain.

[1,717]

A. A larger total supply will be brought forth at a higher prospective price because the higher price makes it worthwhile for producers to commit capital to relatively less promising exploratory and development projects and to incur costs, well in advance of probable revenue, to build up staff and facilities for an expanded

exploration program. Therefore, the unit cost of a larger total supply may be reasonably expected to be higher than the unit cost of a smaller supply.

Q. Your final proposition is that for gas producers price is cost-determining and past cost a hopelessly circular standard. Please explain.

A. Geological and geophysical expenses, and in degree lease acquisition and exploratory drilling costs, are somewhat in the nature of research costs. Investment of available funds in exploration for gas and oil is reduced when alternative opportunities appear to be more profitable relative to risks assumed and are increased when gas and oil prospects are more favorable. Costs tend to be price-determined because of this controllability of exploratory effort.

In utility regulation, costs can be used to fix prices; in the case of the competitive gas producing

[1,718]

indusrty, prices are cost-determining because costs to be incurred tend to be consciously limited to those warranted by the price allowed. Therefore, no matter how deficient the resulting gas supply, the costs actually incurred will appear to confirm the reasonableness of the existing price when tested on a cost of service basis. The historical cost of service method may show a lower cost per Mcf produced even though unit costs of input resources and unit cost of new supplies are increasing. Indeed, the rise in cost level in relation to prospective prices is likely to be the cause of the reduction in expenditures, and therefore create an illusion of reduced costs.

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and thus bring about whatever gas supply expansion is required to meet consumer demands.

Comparative evaluations of alternative investment opportunities by gas producers are made by methods and by reference to cost concepts which are quite unlike those used in the cost estimation formulae which have been used in gas producer regulation. For these reasons, the functional relationship between a fair return and attraction of capital is destroyed by the limitations of the cost formulae.

IV. Relationship Between Gas Supply and Price

Q. Is the conventional concept of supply elasticity useful for the regulatory purpose?

A. The concept of supply elasticity, as commonly defined, concerns the supply curve, meaning the quantities which would be forthcoming at a given time at each price within the range of hypothetical prices. This is a static concept in the sense that parameters other than price, such as technology and cost of input resources, are assumed to be unchanged. Moreover, the academic concept in the context of equilibrium analysis assumes that price reflects a normal profit at which each firm is

willing to produce, so that it is different from cost in the business sense.

The effects of regulatory action with respect to price work themselves out over time under a complex set of changing conditions, instead of under constant conditions. The regulatory inquiry must be directed to the

question of what would be the probable effect of change in regulated prices on future supplies, in the light of current and prospective conditions of exploration and development.

Q. How does the profit incentive affect the shape of the supply curve under any given set of economic conditions?

A. Such a supply curve is not necessarily a smooth curve. The responsiveness of supply to price change depends upon institutional factors and upon the businessman's idea of cost and profit in relation to price.

Q. What are the factors other than price as such which determine the relationship between price and supply brought to the market over time?

A. The relationship between gas supply and price over time may be influenced by momentary inflation, by change in real cost of input resources,

[1,722]

the availability of input resources, changes in alternative investment opportunities, development of new producing areas, size of prospective reservoirs, changes in business confidence, degree of directionality of exploratory effort, change in the technology of the industry, and other factors which influence business decisions.

Q. What relation does cost have to the determination of the elasticity of supply?

A. Measurement of the cost of gas and of elasticity of gas supply are related and interdependent problems. The difficulties inherent in attempts at cost measurement are well-known. Incentive for investment is provided by the prospect of profit commensurate with that available from alternatives, by the relationship between price and

the businessman's view of cost, not by price as such. The trends in productivity of drilling, in drilling costs, and in costs of other components of input resources unavoidably become aspects of a quantitatively measured supply elasticity which is useful for the regulatory purpose. This difficulty is compounded when the measurement is concerned with the future instead of the past.

Q. Why is business confidence a factor which influences

gas supply independently of price?

A. The effectiveness of a given field price as an investment incentive depends upon the regulatory climate and degree of business confidence. To illustrate, business confidence was further impaired by the decision in the *Southern Louisiana* area proceeding for four reasons: (1) because producers believed the ceiling prices fixed by the Commission were far too low, (2) because they felt that to require refunds of revenues collected at the guideline prices established by the Statement of General Policy in 1960 was unfair, (3) because assuming prices to be cost-based, average unit cost estimates were made the measure of the ceiling price, so that it was not possible for producers as a group to realize revenues equal to cost as estimated, and (4) because the dual- or multiple-price plan was based on the invalid theory that windfalls would be given to producers if prices for flowing gas were equal to the cost of replacing the gas.

Q. Is this catalogue of complexities intended to suggest that no effort should be made to measure price elasticity?

A. No. If the Commission is to use price as a tool

to bring forth needed gas supplies, it must give consideration to the probable effect of a given change in field prices. But regulators should not assume that it is possible to predict the precise quantity of gas which will become available at any given price. One should not lose sight of the complexities of the real world in a search for certitude. The influence of price on supply should be viewed as a matter for consideration by exercise of informed judgment in the light of reason and practical experience, not as a subject easily susceptible to precise statistical measurements.

A precise quantification of the price-supply relationship is unusually difficult in this industry because:

1. Gas production is subject to exceptional time lags between investment decision-making and commitment of new supplies to the market; and
2. The relationship between investment and supply is uncertain.

Q. Do you have any statistical evidence concerning the relationship between the field price of gas and activity in the search for gas?

[1,725]

A. Chart 1 of Exhibit No. 24 (JRF-1) shows for the Southwest area the historical relationship between the initial price for gas sales and exploratory drilling productive of gas over the period 1945-1969. As is evidenced by the Chart, there is a strong relationship between the initial price for gas sales (in constant dollars) and the footage of exploratory gas wells. On the average, during 1950-1969, an increase in gas prices of

10 percent was accompanied by a 15 percent increase in exploratory gas drilling.

The gas prices represent average annual new contract prices. The gas prices are expressed in terms of constant 1958 dollars. The chart is drawn in the same format as the conventional supply curves.

The same data are shown in somewhat different form by Chart 2 of the Exhibit. This chart shows the change over time in both initial prices for new gas sales and in exploratory drilling productive of gas in terms of index numbers, with 1947-1949 as base. The chart also includes the price series in terms of actual prices, that is, in money of current purchasing power. It is evident that from 1945 to the 1957-1959 period, a

close relationship existed between the increase in gas prices and the increase in exploratory drilling productive of gas. The increase in gas exploratory drilling until the 1957-1959 period was considerably more rapid than the increase in new contract prices expressed in money of constant purchasing power. After 1957-1959, the decline in gas exploratory drilling was more rapid than the decline in gas prices.

Q. Is it possible that the increase in exploratory drilling through 1957-1959 and the decline during the 1960's is attributable to the changes in exploratory drilling for oil?

A. It does not appear so. As is indicated by Chart 3 of the Exhibit, the trend in exploratory drilling for gas after 1956 has been quite different from the trend in exploratory drilling for oil. The continuing rise in gas prices resulted in a continued increase in the amount of exploratory gas drilling from 1956 to 1959, even

though exploratory oil footage declined sharply after 1956. Further, the decline in exploratory oil footage from its peak has been much sharper than the decline in the footage of exploratory gas wells.

Q. What is the relationship between field price and

[1,727]

development drilling productive of gas?

A. Development drilling generally follows the trends of exploratory drilling with some time lag. Of course, this lag is to be expected.

Chart 4 of the Exhibit shows the close relationship between exploratory and development footage productive of gas. It is assumed that development drilling lags exploratory drilling by approximately two years, and the figures for development drilling are plotted to take into account this two-year lag. Thus, the peak of development drilling productive gas, which is plotted on the chart as of 1959, in fact occurred in 1961, two years after the peak in gas exploratory drilling.

The chart shows a close correspondence between changes in exploratory drilling and changes in development drilling two years later.

Q. Does the mere fact of a close correlation between change in field prices and change in level of exploratory and developmental activity prove that the supply of gas depends upon price?

A. I find no rational explanation of the close correlation between gas prices and activity in drilling productive of non-associated gas outside the

[1,728]

hypotheses (1) that the search for gas is in large part directional and (2) that the change in level of gas

prices largely caused the increase in finding activity prior to 1960 and the decline after 1960. It would be irrational to conclude that the increases in exploratory and developmental drilling experienced over the long term of years after 1945 were not dependent upon the increase in gas prices from the 1945 average of 4.0 cents per Mcf, but were the result of mere chance or incidental to a search for whatever might be found, with no purpose of finding gas independently of oil. It also would be irrational to conclude that the decline in gas exploratory and developmental drilling which followed the decline in contract prices was the result of mere chance or caused by the decline in drilling productive of oil. It must be concluded that gas supply is substantially dependent upon price.

Q. In concluding that gas supply is substantially responsive to price, do you mean that Exhibit No. 24 (JRF-1) provides a precise measurement of supply elasticity?

A. No. The analysis deals with the relationship between price and drilling activity over a historical

period of 25 years. Projections of probable future behavior depend upon our knowledge of past behavior, but the future is not likely to be a mirror of the past. As I have already noted, the price-supply relationship is influenced by many changes over time, such as in business confidence, in alternative opportunity cost, and in productivity of the finding effort.

Use of the relationship between field price and exploratory drilling, as shown by Chart 1, to measure supply elasticity involves questions as to (1) whether the field prices reliably represent price expectations of producers and therefore cost of a given supply, and (2)

whether gas exploratory footage is a good proxy for new supply.

Consideration is given to these complexities and uncertainties in the text of the exhibit. I conclude that, although there is no assurance that the relationship between price and supply indicated by Chart 1 will prevail in the future, the statistical analysis does provide useful information bearing on the responsiveness of supply to price.

Q. Please explain the relationship between the intrastate and the interstate sectors of the market.

A. In addition to the influence of price on supplies

[1,730]

available to the total national market, supply for the interstate sector is influenced by price to the extent that Commission-determined prices for jurisdictional sales vary from intrastate prices for generally comparable supplies. Interstate pipelines must seek supplies in competition with local pipelines and industrial buyers who make purchases directly from producers, and must offer prices at lease equal to the prices paid by competing intrastate buyers.

Prices fixed by the Commission for jurisdictional supplies may influence the prices which are paid in the intrastate sector of the market. Nevertheless, regulatory action to reduce interstate prices below the competitive level gives an advantage to the intrastate buyers and discriminates against the interstate sector of the market. When total national supply becomes insufficient to supply the demands of both the interstate and the intrastate sectors of the market, the intrastate demand tends to be satisfied on a priority basis. The answer is, however, to have enough supply to meet the demands

of both markets and this should bring prices into relative equilibrium.

Q. Does ability to sell in the intrastate instead of

[1,731]

the interstate market have a special significance for oil well gas?

A. Yes. The value of oil well gas to the buyer at the point of its delivery as residue gas is no different from the value of gas well gas which meets comparable quality specifications. When the Commission sets a price for oil well gas or residue gas which is below that value, merely because of its source, producers naturally seek to sell the residue gas in the intrastate market. Therefore, the dependence of the interstate market supply on price is generally the same for oil well gas, although field prices have a lesser influence on exploration for oil well gas.

Q. Does a finding with respect to elasticity of supply have a bearing only on so-called "new" gas, or also on flowing gas?

A. It has a bearing on the price of both new and flowing gas. The impact of the prospective price of new gas on supply should be obvious.

As to flowing gas, there are three interrelated factors bearing on the elasticity of supply. First, under the dual-price system, the field prices paid by pipelines and the prices

[1,732]

to consumers have been held below the cost of replacing the gas. Therefore, the dual- or multiple-price system has contributed to the rapid growth of demand and thereby to the inadequacy of supply relative to demand.

The second factor, possibly the most important, is that the dual- or multiple-price system impairs business confidence. The third is that gas producers rely pri-

marily upon funds from internal sources, and gas being consumed cannot be replaced by funds based on prices below the current cost.

Q. Why does the dual- or multiple-price system impair business confidence and willingness of producers to commit new capital to a search for gas?

A. Business confidence is impaired because prices based on historical cost of service conflict with reasonable business expectations. Businessmen in any competitive industry expect to maintain the integrity of their invested capital by selling the product at the price which reflects current value. In competitive markets, when costs have increased, businessmen do not sell the output of old plants at a lower price than the output of new plants, when the product

[1,733]

is of the same quality and has the same market value. Buyers pay the same price for an equivalent product from an old plant. In competitive markets, prices tend to reflect the present or immediately prospective costs of the goods or services being sold. As Professor Kahn said in *Permian*, "If in fact producers feel they are being unfairly treated, then one may find himself jeopardizing new supply as well."

The second reason for the loss of business confidence is the uncertainty as to how prices which have been fixed for either flowing or new gas may be changed in a second round in area proceedings. The mix of what is classified as "old" and "new" gas progressively changes over time. It is reasonable for producers to be concerned that the present acceptance of the "functionless benefit" argument invites its application at any future time to reduce the price of gas now classified as "new gas", since the theory will then have the same application to

all flowing gas as it has to gas flowing at the present time.

Q. Has any other regulatory agency in the United States adopted a two-price system for companies

[1,734]

under its jurisdiction?

A. No. After World War I in France, rents were controlled to prevent so-called "windfall gains" under the new demand conditions. After 1948, rent controls on new rental housing were removed in order to encourage a more adequate supply of rental housing. However, when rent increases were granted for "old" rental housing, the "new" rental housing was reclassified as "old". Investors soon ceased to believe that new properties would be worth their alternative opportunity cost, and construction for new rental properties practically ceased in France for many years.

Q. You gave as the third reason why the dual-price theory is invalid that gas producers rely on funds from internal sources. Please explain.

A. The Commission said in Opinion 468, quite correctly: ". . . The price for flowing gas must also reflect the producers' need for revenues from their present sales to support future discoveries." Because the search for gas is attended by extraordinary risks, gas producers rely in major part on funds from internal sources. Funds available for exploratory activity are in the nature of equity capital. Equity investors expect returns commensurate

[1,735]

with the degree of risk-taking inherent in the search for new gas supplies and commensurate with change in economic conditions. Equity investors do not willingly

accept the returns provided by a rate of return on an original cost rate base. Historical cost of service pricing does not permit maintenance of the purchasing power integrity of the capital being employed. Moreover, the supplies being withdrawn by deliveries under existing sales contracts cannot be replaced by paying the historical costs of finding, developing and producing equivalent supplies. When demand is increasing, costs are rising, and larger new supply is needed, a larger rather than a smaller flow of funds per Mcf from gas sales is required.

Q. Have changes in the general economic environment also been a factor in the reduction of exploratory activity over the past ten years?

A. Yes. The basic economic trends are described by Exhibit No. 25 (JRF-2). Gross national product, expressed in constant dollars, increased at a compound annual rate of 4.0 percent over the past 20 years, but at a rate of nearly 5 percent from 1960 to 1968. Since 1965 consumer prices have increased at an annual rate of more than 4 percent, and all

[1,736]

prices at a rate of nearly 4 percent. That rate of inflation means a loss of nearly one-third the purchasing power of money within ten years. As a consequence of the inflation, the cost of equity as well as debt capital increased. Average rates of earnings on book equity were 15 percent higher in 1966-1968 than in 1958-1960, for both manufacturers and public utilities. Therefore, reduced field prices curtailed revenues and profits of gas producers under conditions of generally rising costs and improved earnings on book capital in alternative uses. Effective price regulation cannot disregard the trends

with respect to business activity, cost of capital and value of money which determine investor expectations.

Q. It has been contended that, if gas production is an increasing cost industry, supply is "relatively inelastic" and for this reason it is not necessary to reach a judgment regarding supply elasticity. Is this contention valid?

A. It is correct that in the long run gas supply is not likely to increase in proportion to cost and price. Natural gas production is inherently an increasing cost industry. An enhanced supply can not be provided without searching for the relatively

[1,737]

less promising and profitable supplies; thus, under these circumstances, unit cost for this greater total supply will be higher than for a smaller total supply.

The argument that responsiveness of supply to price change is of no importance when less than "unity" was a rationalization, without merit, of the historical cost approach. Because gas production is an increasing cost industry, the responsiveness of supply to price change, over the long term, is less than otherwise would be the case. But this is not to say that an increase in price will not elicit needed supplies or that consumers would prefer to go without gas rather than pay the higher price which reflects the higher cost of a larger supply.

V. Proposed Pricing Policy and Procedure

Q. Within the context of the objectives you have outlined, and taking account of the problems you have considered, will you now state as concisely as possible the policies and procedures which you believe should be adopted by the Federal Power Commission for field price regulation.

A. First, the Commission should reaffirm the conclusion

* * * *

[1,749]

PREPARED DIRECT TESTIMONY OF KENNETH C. VAUGHAN

Q. Please state your name and address.

A. My name is Kenneth C. Vaughan and I reside in San Marino, California.

Q. By whom are you employed, and in what capacity?

A. I am a director of Union Oil Company of California, a member of the executive committee, Senior Vice President of the corporation, and President of the Union Oil and Gas Division. This division is responsible for all domestic exploration and production activities of Union Oil Company of California.

Q. Please summarize your education and business experience.

A. I was graduated from the University of Southern California in 1933 with a Bachelor of Science degree in petroleum engineering. Following my graduation I joined Union Oil Company as a wellpuller. During subsequent years I held such positions as production superintendent in California, manager of field operations in the western region, and manager of natural gas and gas liquids division. In 1959 I was named manager of Union Oil's Gulf division in Houston, in which capacity I supervised all of Union's exploration and development activities in the State of Louisiana and the Gulf of Mexico. In December 1963 I returned to Los Angeles as Senior Vice President in charge of exploration and production for the corporation. In January 1969 I was elected President of

[1,750]

the newly created Union Oil and gas division—the post I currently hold. In this latter capacity I am responsible

for all of Union Oil's domestic exploration and development activities and the natural gas and gas liquids functions of the company are among the activities which are under my supervision.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is twofold. First, I will discuss management's investment decision-making process in general, and in particular as it applies to investment decisions concerning natural gas exploration and the development of natural gas reserves. Secondly, I will present reasons why I believe an increase in the price of both flowing and new gas will result in an increase in the supply of natural gas.

Q. Do you believe Union's management decision-making process is typical of other gas producers?

A. Yes.

Q. Would you please describe the planning process management uses in making investment decisions?

A. The first step management must take involves acceptance of a corporate long-range plan. This plan provides management with the guidelines or parameters within which individual investment decisions are made. We regard our plan

as a blueprint for the future which is based on conditions as they are known and foreseen today. As such, the plan is frequently updated and revised. Our staff groups look at the total economic environment within which we operate and build the plan on that base. We project where our operations and efforts will be concentrated, we look at the possibility of diversification, we project capital expenditures, and we consider alternative methods of

financing our capital expenditures. This then makes it possible to project in broad terms the long-term consequences on the entire company of various major decisions which are being considered. The corporate plan is an effort to select that combination of decisions which, in the light of available knowledge, has a high probability of producing the best long-term results for the company as a whole.

Once a plan is accepted it serves as a guide for our operating divisions which find and analyze most of the investment opportunities submitted for our final decision.

Q. What is the role of capital budgeting in the decision-making process?

A. Capital budgeting involves the same sort of considerations as long-range planning, but it deals with spending and financing plans within a one-year period. An example within the oil and gas division will illustrate the difference. In long-range planning, we consider such questions as the

[1,752]

feasibility of reducing gas exploration programs and manpower in South Louisiana and increasing oil exploration programs and manpower in other areas. In capital budgeting or short-term planning we compare investment opportunities in a particular well or series of wells in South Louisiana with wells in other locations.

Q. Is the budget then set only on an annual basis?

A. No, the capital budget is projected annually but it is under frequent review and as conditions change our plans are also changed. In addition, as each project comes up for investment it is subject to final management review and approval.

Q. How are sources of funds identified in the allocation of capital?

A. I wish to emphasize that capital is allocated to divisions, and to projects within divisions, from the company's total pool of funds. When we make a long-range plan we summarize our opportunities and financial resources for the company as a whole. If we have more opportunities than available funds, then we consider the wisdom of raising new capital. If the budget which is finally approved calls for us to raise new capital, the method of financing is dictated by our judgment of a proper financial structure for the company. That capital is then in effect lumped together with our cash flow from operations. The total funds are then allocated to those projects which have been budgeted. Within this framework, I will

discuss later the need for the Commission to increase gas revenues so as to provide proper economic conditions and additional funds to encourage gas exploration and development.

Q. Once the budget is adopted, how does management go about making individual investment decisions?

A. Management decision-making is a complex and continually changing process which requires balancing a large number of factors within the framework of legal, social and economic parameters. There is no single answer to the question, because no two people will evaluate the variables in the same way, and no two projects are identical. I can, however, describe in general terms the major economic factors that are considered by management in decision-making.

Q. Please do so.

[1,753]

Prepared Direct Testimony of Kenneth C. Vaughan

A. The main economic factors are an estimate of the profitability of the project, a judgment of the risk of the project, and the availability of resources with which to undertake the project.

Q. Please describe how you estimate the profitability of a project.

A. As a basic tool to help management select those projects which have a high probability of producing the best results for the company, a discounted cash flow rate of return analysis has proved to be a satisfactory technique for estimating profitability. In this method the analyst estimates

[1,754]

the earning power of a project and expresses it as an average annual rate of return on investment. Such a rate of return figure means that the project will earn that rate for each year on the cash in the projects and, in addition, eventually recover all costs.

Projects are not measured and compared solely on the basis of their rates of return. We use rates of return as guidelines which provide a useful screening function, and as a major factor in making the final judgment of whether to accept or reject a proposed project.

Q. Is there a single acceptable rate of return?

A. No. An acceptable rate of return will vary with the type of project, with time and with circumstances. In addition, the other main decision factors I mentioned —risk and the company's resources—are weighed in making a final decision. In the case of particular natural gas exploration and development decisions the acceptable rate of return will be influenced by risk, alternative investment opportunities available to the company, lease commitments, the availability of men and equipment,

and the basic goals set forth in the corporate long-range plan.

Q. The second factor you mentioned was risk. What is the role of risk in management decision-making?

A. The appraisal of risk is a major qualitative factor in management's decision-making process. Risk is an expression

of all the uncertainty that surrounds the analyst's estimate of rate of return. Risk varies widely, and the acceptability of rates of return varies with it. A relatively low rate may be excellent for a low-risk venture, and a relatively high rate of return inadequate for a project with a highly uncertain future. Risk stems from many sources. Management if often unavoidably working with incomplete information at the time a proposal is studied. Another source of risk is the uncertainty of forecasts. Finally, there is the unlimited combination of ways in which men and machines can fail to perform as predicted.

Q. How do you rate the risk of exploration?

A. Exploration for hydrocarbons is very risky as compared with many other business ventures we may undertake. It is necessary to irrevocably commit large sums of monies to exploratory ventures, recognizing that in the United States we currently expect that only one well in fifty will be commercially productive. In addition, the salvage value of an exploratory failure is relatively much less than the salvage value associated with most business failures.

Q. What conditions affect management's evaluation of the risk factors?

A. Risk is difficult to assess because it varies from project to project. For example, risk varies because of differing outlooks about all economic conditions in the

[1,756]

future. Inflation is an example. Risk varies according to the magnitude of the investment in relation to the capital structure of the company, and can be altered by changes in the tax laws. We just experienced such a change. To the extent that petroleum companies are unable to offset their increased taxes by increased field prices, the attractiveness of exploration as an investment has been reduced.

Ultimately the manager has to evaluate the risk of every proposal. There is no standard scale of values he can use, but with every project a limit is reached where risk condemns the project. A final decision is made by using judgment based on his knowledge and experience.

Q. The third factor you mentioned was the availability of resources with which to undertake projects. How does this affect decision-making?

A. Some of the resources are clear-cut—like capital, men, management and equipment. These are limited resources and the availability of all of them can be critical to a project. When one of them is scarce, this factor will weigh heavily in management's decision.

Q. Other than the clear-cut physical limitations you mentioned, are there any other factors which cause resources to become scarce?

A. Yes, an important one involves the concept of alternative investment opportunities. At the low end of the

[1,757]

alternative investment scale are the virtually riskless municipal bones available today yielding approximately 6 percent tax free. There is a continually changing and virtually unlimited number of investment opportunities with varying risk available to management and any given investment must compete with these opportunities for the available funds.

Every project we undertake, we do at the sacrifice of some other project. Within a limited capital budget we must forego one project in order to accept another. Thus, if we have a wide range of attractive alternatives, the resources we have available must be channeled to the most attractive of these.

Q. Would you describe the process of making a management decision to drill an exploratory or development well?

A. In the Union Oil Company, we have organized our oil and gas division into regions and districts. New exploratory and development prospects are first analyzed at the district level and those which are potentially more profitable are recommended to the regional office. The regional offices in turn evaluate all of the proposals received from the district offices and submit to my office for further evaluation those which meet or exceed guideline requirements set forth in our long-range plan. They also submit proposals which, even though they do not meet the guideline requirements, have other compelling reasons for investment.

[1,758]

Q. What are some of the factors that are considered in evaluating specific exploratory well proposals?

A. First, we consider the geologic merits of the proposal, which include:

—Size of the potential reservoir.

—Degree of structural closure.

—Character of the reservoir rock.

—Type of hydrocarbons that is expected.

—Potential of the area in which the well is proposed.

—Value of the information the well will develop.

If the prospect is attractive geologically, we consider its economic merits. The economic attractiveness depends on:

—Anticipated revenue from the sale of products.

—How long it will take to market the products.

—Cost of leases.

—Geological and geophysical costs.

—Cost of the initial well.

—Cost of subsequent development wells.

—Operating and maintenance costs.

—Transportation and marketing costs.

—Taxes.

Examples of other factors are:

—Contractural requirements, for example, the terms of a lease.

—Availability of men and equipment.

[1,759]

Q. After the process of elimination at the regional level, is there any further screening performed?

A. The oil and gas division in our company, and I believe this is representative of most oil companies, has an annual budget meeting where various exploratory and development projects are presented from all of our regions. These are the wells and related projects that have already been classified by the various regional offices as the most promising from their area and we now evaluate these wells and projects against each other and select the combination of ventures which we estimate will provide the best results to the company as a whole. My staff and I participate in both the regional and divisional reviews.

Q. Does inclusion of an exploratory well in the oil and gas division budget constitute authority to spend money?

A. No. A final review of capital expenditures is made by the executive committee at which time oil and gas division projects compete with requested expenditures from all other divisions of our company. We are in direct competition for funds with our refining, marketing, petrochemical, international, all of our other subsidiary operations, as well as potential diversification projects. It is management's responsibility to arrive at that mix of projects which will optimize the company's long-term growth and if more profitable projects are available, exploratory well projects will not be

[1,760]

approved.

Q. If either oil or gas exploration were made more attractive, how would your company respond?

A. We would take the following steps:

1. The oil and gas division would immediately review all the exploration and development projects in its portfolio in the light of the new conditions.
2. If that study showed we now had some projects more attractive than those previously budgeted—either in the oil and gas division or elsewhere in the company—we would make substitutions within the budget.
3. If we found we had profit opportunities greater than the previously approved budget, we would reopen the budget and decide whether or not to commit new funds to oil and gas exploration.

Q. To what extent does capital rationing exist?

A. Capital is always costly; consequently, we are always in a situation of limited capital. We currently have a large and ever-changing number of opportunities to invest this capital. The result, as I mentioned earlier, is that individual projects must compete with many other possible projects for available funds. If we had more money available today, we would have no trouble finding investments for that capital.

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[1,762]

Q. Would an increase in the prices of natural gas result in increased exploration and development activities for natural gas?

A. Yes. We already feel that the market in terms of the relationship of supply to demand is attractive. We believe demand for gas will continue to be strong. I am confident domestic natural gas can be found and developed in sufficient quantities to narrow the gap between demand and supply at price levels which will be competitive with alternative fuels.

Q. What would induce management to increase its exploration and development activities?

A. An increase in the price of all gas, both flowing and new. It is my company's view that the best way to induce such increased activity would be for the Commission to allow increases in flowing gas prices, up to a new ceiling to be established for new gas, but not in excess of price levels provided in existing contracts.

Q. Why do you believe an increase in price of new gas will result in an increase in exploration?

A. An increase in the new gas price will make economically attractive a large number of additional exploratory prospects including many in South Louisiana. Under current conditions we have a number of drilling prospects which would be attractive at a higher price. I can assure you such a higher price would cause us to drill prospects which we would

not otherwise attempt.

Q. Why do you believe an increase in the price of flowing gas will also result in increased exploration and development?

A. In my opinion, an increase in the price of flowing gas, as well as new gas, is the necessary catalyst to provoke the needed increase in exploration and development efforts. Current prices have thus far failed to produce the growth of gas supply the market needs. Raising the price on flowing gas will be the quickest and most effective way to correct this situation because a higher price for flowing gas will lessen the capital supply problem at the same time it makes exploration more attractive. When an operator is assured that his existing reserves will produce a satisfactory cash flow, he will have the desire, confidence, and capital funds to replace those reserves. In addition, an increase in the price of flowing

gas will result in an immediate increase in reserves as the higher price will extend the economically productive life of known pools and thus make possible the recovery of reserves which would otherwise not be produced.

Q. If companies select their investments from among alternatives, how can the Commission know that the increased revenues obtained from increased prices of flowing gas will be used for gas exploration and development?

A. With due regard to social and environmental

[1,764]

considerations, we have an obligation to our stockholders to select the most profitable alternative. Accordingly, no firm commitment can be made to use increased revenues from increased gas prices for further exploration. It should be obvious, however, that gas exploration and development will be much more attractive than it was before the increase. It will also be more attractive than before relative to the spectrum of other alternatives. We are in the natural resources business. Our expertise calls for us to remain in this business. There is, therefore, a strong probability that increased expenditures for exploration will result from the increased prices. To question that increased gas prices would lead to increased gas exploration assumes that industry management acts in an irrational fashion, i.e., that profit opportunities will be ignored.

Q. What are your views concerning the Commission's past pricing policies?

A. They have resulted in prices that have not elicited sufficient supply to meet consumer demands. The effort the industry puts forth domestically to find new sup-

plies and further develop existing supplies is directly related to the price of natural gas. Since exploration and development expenditures are controllable in the long run, the industry will attempt to limit the costs incurred to those justified by revenue. The price which is set for gas will determine

[1,765]

the maximum costs which management is willing to incur when developing additional supplies. Once costs as viewed by management come sufficiently close to revenue, the attractiveness of gas investment, relative to alternate opportunities, declines.

Q. Do you have an opinion on how to narrow the gap between supply and demand?

A. Yes. In my opinion, the Commission must consider two overriding factors:

—The current and future energy needs of existing gas consumers.

—The future needs of new consumers for energy.

The future needs of most new energy consumers can be satisfied by their choice from among the complete spectrum of energy sources available: coal, fuel oil, electricity (including nuclear power), Canadian gas, LNG or synthetic gas.

Increased quantities of gas to supply the future needs of most existing gas consumers must be satisfied by a gaseous form of fuel because most gas transportation and utilization equipment is designed to accept only gas.

With these factors in mind, I believe the Commission should:

—Estimate the growth in demand for gas under current conditions.

—Estimate the deficiency in gas supply under current

[1,766]

conditions.

—Estimate the costs involved in supplying gaseous fuels by means other than domestic natural gas production.

—Estimate the costs to consumers involved in the forced substitution of alternative energy sources.

Based on this information the Commission could establish a framework of prices at which domestic natural gas will be competitive with these alternatives.

It is my recommendation that the Commission give substantial weight to this alternative fuel price concept in establishing an improved approach to producer regulations.

Finally, I would observe that the gas consumer would not be penalized by this approach because, under the supply shortage, consumers would inevitably be faced with higher prices or would be forced to turn from domestic natural gas to other more expensive energy sources.

Q. Other than price, are there any other regulatory factors which influence management's decisions?

A. Yes. Management's confidence is an important intangible. Management should be given assurance that once gas contract prices, including reasonable escalation, are approved they will not be subject to future reductions.

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[1,916]

Prepared Rebuttal Testimony of Radford L. Schantz

[1,916]

PREPARED REBUTTAL TESTIMONY OF RADFORD L. SCHANTZ

Q. Are you the same Radford L. Schantz whose qualifications and direct evidence appear at TR. 1494 to 1609 in this proceeding?

A. I am.

Q. For what purpose are you now testifying?

A. My purpose is to present rebuttal testimony to Witness Frazier's direct testimony, which appears at TR. 1330 through 1369 in this proceeding, and which was prepared in behalf of the Associated Gas Distributors.

More specifically, my rebuttal pertains to aspects of Mr. Frazier's analysis of supply and demand, price trends, and interfuel competition.

* * * *

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A. Yes. Schedule 4 shows for 13 cities in the New England Mid-Atlantic Region a comparison of season house-heating costs for gas, fuel oil, and electricity over the ten-year period from 1959 to 1968. These costs are published annually for 66 cities throughout the United States by the Independent Natural Gas Association of America. The publication is titled, "Comparison of Season House-heating Costs for Gas, Fuel Oil, Coal and Electricity." Data for the 1969 heating season have not yet been published.

The purpose of the INGAA study "is to show in dollars the comparative costs of the consumers of natural

gas, oil, coal, or electricity for doing an equivalent job of heating an average or typical house during the 1968 heating season."

For example, Schedule 4 of my Exhibit shows

[1,929]

that in Atlantic City the cost of heating a house by gas in 1968 was $119.60. The equivalent cost of heating by fuel oil was 132.41; and the equivalent cost of heating by electricity was $292.46.

To obtain equivalent hearing costs, these data have been adjusted for thermal efficiencies as between the three sources of heat—gas, oil, and electricity. Therefore, the cost comparison is based not only on delivered price and heat content of the fuels, but also on the relative thermal efficiencies.

Q. What assumptions are employed in determining these cost data?

A. The INGAA report states—"Assumptions are predicted on the use by an average or typical home in each community. Generally figures for gas are after deduction for base load, i.e., cooking and hot water heating, although this varies considerably."

Q. Do other studies of gas heating also compute costs after deducting for base load uses?

A. Yes. This is a typical procedure because the cost being determined is for gas househeating, not the average cost for all uses of gas. For example, the Bureau of Labor Statistics computes the cost of gas heating after deducting for "base load" uses of gas. As another example, Mr. Frazier deducts for base load uses when he determines

the heating cost of gas and electricity. (Exhibit 17, Schedule 2, at Columns 5 and 6.)

Q. What is the source of the data published by INGAA?

A. According to the INGAA study, "the data from which these costs were compiled were obtained in each instance from the distribution utility serving gas in the community named." Therefore, the data shown on Schedule 4 are primarily, if not wholly, provided INGAA by the Associated Gas Distributors, since I have limited the showing on Schedule 4 to the New England-Mid-Atlantic region.

Q. What is your view regarding the reliability of the data provided INGAA by gas distributors?

A. I believe these data are reasonable estimates of interfuel competition. Each distributor has its own particular set of circumstances involving interfuel competition which may change at any time for a large variety of reasons. It is reasonable to assume each distributor is continuously studying his own situation and the results of these studies are reported annually to INGAA. It might also be noted that the Bureau of Labor Statistics relies on data provided by gas distributors in determining heating costs.

In fact, the question of acceptability of the

INGAA studies is much the same as the question of acceptability of the Future Requirements Committee studies which also importantly rely on data and estimates provided that Committee by gas distributors. Thus, I accept and use the INGAA studies for the same rea-

sons I accepted and relied on the Future Requirements Committee estimates in preparing my direct evidence submitted on May 1 in this proceeding.

Q. Describe the efficiency factors underlying the equivalent heating costs reported by INGAA.

A. These efficiency factors are set out in the INGAA studies. For cities located in the New England-Mid-Atlantic region, 1968 househeating thermal efficiency of gas averaged 78 percent of the efficiency of heating by electricity, while the efficiency of heating by fuel oil averaged 86 percent of the efficiency of heating by gas.

The source of these efficiency data were provided in each instance by the gas distribution utility serving the community, according to INGAA. Furthermore, according to INGAA, the thermal efficiency of gas compared with oil is greater than as reported because "studies which have been conducted for Consolidated Edison Company of New York, Inc. and for Long Island Lighting Company indicate that the difference in efficiencies shown in

Table V ('Thermal Efficiency') are conservative."

Q. Will you now summarize the cost of househeating shown on Schedule 4?

A. The comparative cost of househeating is shown over the period 1959 to 1968 for 13 cities geographically scattered throughout the New England-Mid-Atlantic region of the United States.

As of 1959, oil was underpriced compared with gas in six cities, and gas was underpriced compared with oil in seven cities.

Over the period 1959 to 1963, the relative cost shifted in favor of gas at a number of these Northeastern cities;

and by 1963, gas was underpriced relative to oil in 10 of the 13 cities.

This trend favoring gas continued and by 1968 gas was underpriced relative to fuel oil in all 13 cities.

Q. What has been the degree of gas underpricing relative to fuel oil in the New England-Mid-Atlantic region?

A. This is shown on Schedule 5. On this schedule the househeating cost of gas (as reported by INGAA) is divided by the househeating cost of oil for the years 1959, 1963, and 1968. The result is shown for these years in Columns (1), (3), and (5) of Schedule 5.

As of 1959, the relative cost of househeating was about equal as between the two fuels. Therefore,

on the average for the 13 cities, Schedule 5 shows that the cost of gas was underpriced by only 2 percent compared with oil. By 1963 the cost of gas heating was underpriced, on the average, by about 8 percent compared with oil heating. By 1968, with the trend accelerating, gas was underpriced on the average by about 17 percent compared with oil.

Q. At TR. 1352 Mr. Frazier states, "Electricity is now emerging as a severe competitor for gas in the very market to which gas has been looking for growth—new home-heating." Does the INGAA househeating cost data shed factual light on this matter?

A. Yes. Based on these and related data, it can be categorically stated that the cost of gas househeating has been and continues to be substantially underpriced relative to electric househeating, in the New England-Mid-Atlantic region, and indeed throughout the United States.

INGAA did not commence to report the cost of electric househeating until 1963, when comparisons were shown for 9 of the 13 cities in the New-England-Mid-Atlantic region. In that year, gas heating was shown to be substantially underpriced, averaging for these 9 cities about 56 percent of the cost of electricity (Schedule 5, Column 4).

By 1968 data reported by gas distributors to

INGAA set out the cost of electric heating for 12 of the 13 cities, and on the average gas was even more underpriced amounting to only 53 percent of electric heating cost (Schedule 5, Column 6).

Q. I notice in Column 6 at Schedule 5 a considerable diversity in the degree to which gas heating is underpriced comparative with electric heating. Can you explain this diversity?

A. It is true that there is quite a range. At the low end, the cost of gas heating in Providence, Rhode Island is only 31 percent of the cost of electric heating. At the high end, the cost of gas heating is as much as 88 percent of the cost of electric heating in New York City. Upon examining the data for the 12 cities, there does seem to be one statistical correlation. Without exception, the higher gas/electric cost ratios are for cities served by combination (electric and gas) utilities, and the lower gas/electric cost ratios are for cities served by a separate gas distributor and a separate electric utility. For the four cities served by combination utilities, the average gas/electric cost ratio in 1968 was 75 percent. For the remaining eight cities, the average gas/electric cost ratio in 1968 was 42 percent.

Q. In spite of gas being substantially underpriced relative to electricity, is it not true that electricity

is a vigorous competitor for heating markets in some areas?

A. Yes. This is true in some areas, primarily in the Southern part of the United States. This competition is described by the 1968 INGAA report as follows:

> "Competition from Electricity
>
> "Following the practice inaugurated in our survey five years ago, figures on costs for electric house-heating are presented herein, where available. While responses to our request for data indicate that in some parts of the country competition from the electric industry for househeating loads runs from 'minor' to 'token,' in some other areas the competition is strong. More and more the reports in a number of areas reflect aggressive efforts by the electric industry to advance its position in the househeating field.
>
> "Typical responses from several distributors as to electric competition were: 'Aggressive' and 'increasing due to subsidies being offered.' Others commented that the electric industry has made inroads into the high rise apartment and office building areas through construction of all-electric installations, while still others noted that the 'underground wiring allowance is difficult to overcome.'
>
> "Subsidies being offered by utilities in various areas in order to have their respective fuels used in new developments have been the subject of court suits and of study by state and city regulatory agencies, with the results of these legal activities expected to come a head in the future. Such promotional activities by the fuels industries also were the subject last year of hearings before a House of Representatives Subcommittee."

[1,936]

In summary, gas distributors report that electric utilities seek to overcome substantial gas underpricing by aggressive selling and subsidies.

Q. At TR. 1349 of his testimony, Mr. Frazier states:

> "The most visible form of competition between oil and gas, in most areas of the country, is in the field of heating residences, small apartment houses, and small commercial installations. It should first be noted that in this market, price is only one of a number of competitive factors, but it is an important one."

Mr. Frazier does not identify the other factors. Could you speak to these other factors?

A. Yes, I Can. By price, Mr. Frazier speaks of the offering price of No. 2 fuel oil and the offering price of natural gas. Another factor is the thermal efficiency of these two fuels which Mr. Frazier did not account for, but which is provided INGAA by gas distributors and reflected in the comparative cost data shown on Schedules 4 and 5 of my Exhibit.

Otherwise, aggressive selling by gas distributors has been an important factor. Of great assistance to the selling efforts of these distributors is the fact they are selling a premium fuel compared with fuel oil. This premium is made up of a composite of several factors—dependability, convenience, cleanliness, and versatility. As an additional factor, the initial cost of installing a gas furnace for househeating is less than the cost of

[1,937]

a fuel oil furnace, and the amortization period is longer. Therefore, the amortization cost of the furnace is less to the consumer for gas comparative with oil.

Q. Can you qualify these other factors favoring gas heat compared with oil heat?

A. The only factor which I can qualify, other than the offering price and thermal efficiency, is the amortization cost of the furnace.

Q. Please do so.

A. Based on research I have undertaken, it may be estimated that in the New England-Mid-Atlantic region the average amortization cost of a residential oil furnace system (including the oil storage tank) is in a range of $46 to $58 per year compared with a range of $29 to $33 per year for a residential gas furnace system.

Q. Mr. Frazier, in speaking of competition between fuel oil and gas for the heating market, asserts at TR. 1350—"In other parts of the country, notably the Middle Atlantic States, there is rough price equality between these two fuels. Finally, in New England, gas must be sold at a slight price disadvantage." Do you agree with this conclusion?

A. No, I do not. Mr. Frazier draws his conclusion on the basis of only the offering price. But this is an erroneous comparison because he failed to quantify other

factors influencing this competition, although they can be quantified. By adding the amortization cost for the investment in the furnace system to the fuel cost adjusted for thermal efficiency (Schedule 4), we arrive at a reasonably accurate measure of the comparative cost of oil *vs.* gas househeating in 1968:

COST OF GAS HOUSEHEATING AS A PERCENT OF THE COST OF OIL HOUSEHEATING IN 1968

	As Reported By Gas Distributors	After Adjustment For Amortization Of Investment In Furnace
New England Region	87%	81%
Mid-Atlantic Region	81	77
Total New England-Mid-Atlantic Region	82	78

Thus, after taking into account thermal efficiency and investment in furnace equipment, it may be concluded that gas heating is underpriced by 19 percent in New England, 23 percent in the Mid-Atlantic, and 22 percent for the total New England-Mid-Atlantic region.

It is in part because of this economic advantage that "the trend in sales in the last two decades has been very markedly upward for gas heating in both of these areas, and in point of new installations, gas usually enjoys a marked ascendancy." (Mr. Frazier's testimony

[1,939]

at TR. 1350).

Q. Have gas distributors been aggressive in exploiting this economic advantage in this region?

A. Yes, and their success has been reported in annual reports to stockholders.

Q. Could you provide us with several examples?

A. Certainly. As one example, the Brooklyn Union Gas Company, a member of AGD, had this to say in its 1969 annual report:

> "Load growth should be substantial next year. The very good record of space heating sales in 1969 should carry into the seventies. Most of the new heating load has been from the conversion of existing buildings, so even though new home construction may continue to be depressed, it won't hurt us where we are presently growing. The big jump in conversions from oil to gas heat in 1969 portends victory in the battle for the space heating market. Gas heat with its cleanliness and delivery advantages will still be cheaper that some heating oil even with the pro-

posed [Brooklyn Union] rate increase, and chances are that the price of oil will go higher.

"We are now getting the heating load in nine out of ten new apartment buildings. The New York City Housing Authority insists that all of its construction will use gas under our combination fuel temperature controlled rate. In addition, the tighter restrictions on sulfur content of heating fuels, which took effect on October 1, 1969, should help us convert more existing buildings."

As a second example, the Connecticut Natural Gas Corporation, another AGD member, sets out a table in its 1969 annual report showing the cost of househeating

in its service area comparative for gas, fuel oil, and electricity. This table is shown on the following page of my testimony. It will be noted that the Connecticut Natural Gas heating cost data allow for efficiencies and exclude cooking and water heating as a base load, as is done in the INGAA heating cost studies.

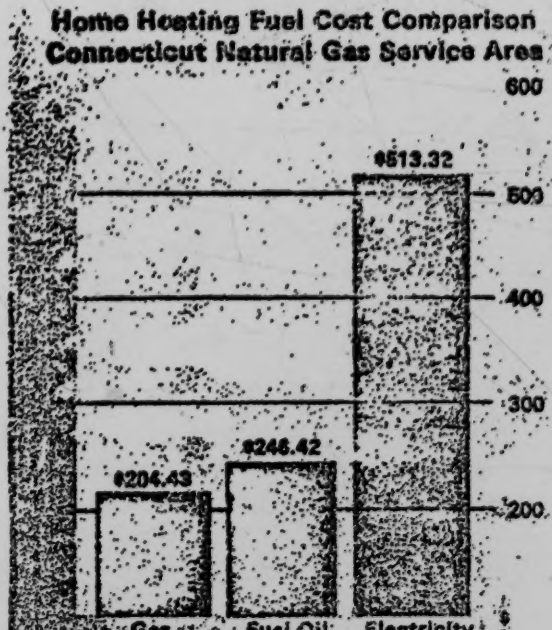
Q. Will you now summarize your testimony on the competitive position of natural gas in the New England-Mid-Atlantic househeating markets?

A. Natural gas is substantially underpriced in these markets comparative with both fuel oil and electricity. It may therefore be concluded, with one important proviso, that the price of gas could increase substantially in the New England-Mid-Atlantic region without jeopardizing the heating market for gas.

Q. What is that proviso?

A. The one important proviso is that gas distributors must have a sufficient and growing supply of natural gas to serve existing customers and to meet an orderly growth in new customers. And the only way gas distributors can have this supply assurance is by a sufficient incentive being allowed domestic gas producers to explore and find increasing reserves additions.

If the incentive is not provided, then reserves additions will continue to fall below production requirements



The average CNG customer uses 134,500 cubic feet* of gas for home heating. One cubic foot of gas equals 1000 BTUs, (British Thermal Units, international standard of heat measurement). With rates currently in effect, gas continues to be the most economical fuel for home heating. The costs to provide the same amount of heat with other fuels, allowing for efficiencies, is shown above.

*Excluded is average base load for cooking and water heating.

Source: Connecticut Natural Gas Corporation, 1969 Annual Report to Stockholders, at page 8.

[1,942]

and gas shortages will increasingly occur. This will have a most deleterious effect at the market place and the growth which gas distributors require and have enjoyed will cease. This, of course, will adversely affect the load factor of both pipeline and distributor, and will force up the burner-tip price of gas but without the concomitant benefit of increasing gas supplies.

Q. At TR. 1340 and 1341 Mr. Frazier observes that "probably the most important single factor" affecting the competitive posture of gas distributors is the city gate cost of gas. Do you agree with this statement?

A. No, I do not. While the city gate cost of gas is certainly important, the most important single factor affecting the competitive posture of distributors is the burner-tip cost of gas, as set out on Schedule 4 of my Exhibit.

The burner-tip cost is made up of three components—the field price, the transportation cost, and the distribution cost. One example of the relative importance of these components is provided by sales of gas by Transcontinental Gas Pipe Line Corp. as the sole supplier to South Jersey Gas Company who, in turn, retails gas in Atlantic City and other communities in Southern New Jersey. According to the 1969 Transco annual report to stockholders, the average price paid by that pipeline for purchased gas

[1,943]

was 18.7 cents per Mcf. Under their contract demand service, Transco sold this gas to South Jersey Gas Company at 36.6 cents per Mcf at an almost 100 percent load factor. South Jersey Gas Company in turn resold

this gas to residential customers at approximately $1.62 per Mcf, according to their annual report.

It should be noted that Transco put into effect a rate increase as of January 1, 1970, and South Jersey Gas Company has also filed for a rate increase, according to their 1969 annual report to stockholders. Therefore, it may be expected that the pipeline transportation and the local distribution costs will increase somewhat in the near-term future.

Q. Have other gas pipelines recently sought rate increases or are they currently seeking rate increases?

A. Yes. This is happening throughout the United States. As Mr. Frazier observed at TR. 1343 (footnote 5), the average price for pipeline sales for resale by interstate companies in January 1970 was 36.79 cents per Mcf, 2.04 cents higher than a year ago, according to an FPC press release. Thus, Transo is only one of a number of interstate pipelines seeking rate increases throughout the country at this time. Whether this rate increase trend by interstate gas pipelines will continue to increase and amount to 5 cents per Mcf in several years, as asserted

by Mr. Frazier (TR. 1343), cannot be determined at this time. It is, however, fair to say that there will be further increases in the cost of transporting gas in interstate commerce.

Q. You referred to South Jersey Gas Company recently filing for a rate increase. Have other gas distributors in the New England-Mid-Atlantic region also sought rate increases?

A. Yes, they have. For example, a check of the 1969 reports of some but not all of the Associated Gas Distributors operating in this region indicates at this time

at least 17 distributors have recently received rate increases, or are processing rate increases before their local regulatory commissions. These companies are: Boston Gas Co., Brooklyn Union Gas Co., Cambridge Gas Co., Central Hudson Gas & Electric Corp., The Greenwich Gas Co., The Hartford Electric Light Co., Long Island Lighting, New Bedford Gas and Edison Light Co., New York State Electric & Gas Corp., Public Service Electric & Gas, Southern Connecticut Gas Co., United Gas Improvement, Worchester Gas Light Co., as well as South Jersey Gas Corp.[2]

[1,945]

In the composite, these 17 distributors account for about 529 billion cubic feet of annual gas sales, or more than half of total gas sales by the Associated Gas Distributors in this region.[3]

Thus, it is seen that a good portion of the gas distribution companies in both New England and the Mid-Atlantic areas have applied for rate increases at this time in order to provide for them a continuing opportunity to earn a fair return. That they do, in fact, seek rate increases indicates that their analysis of interfuel competition in the househeating market is based on the same data they provide INGAA; i.e., data which show gas to be substantially underpriced relative to oil and elec-

[2] Additionally, it should be noted that many gas distributors (as least 37 companies in the AGD group) in the New England-Mid-Atlantic region have automatic purchased gas adjustment clauses so that if the cost of purchased gas increases, they will be able to automatically pass on these costs to the ultimate consumer without seeking a rate increase from the state or local regulatory commissions.

[3] An even larger portion of electric utilities in the New England-Mid-Atlantic region have recently received or are processing rate increases.

tricity. As Brooklyn Union stated in its 1969 annual report—

> "The big jump in conversions from oil to gas heat in 1969 portends victory in the battle for the space heating market. Gas heat with its cleanliness and delivery advantages will still be cheaper than home heating oil even with the proposed [Brooklyn Union] rate increase, and chances are that the price of oil will go higher."

In other words, distributors in the New England-Mid-Atlantic region are not concerned enough over interfuel competition to refrain from filing rate increases; yet

[1,946]

Mr. Frazier would apparently say there should be no apreciable field price increase because the position of gas in interfuel competition will be placed in "serious jeopardy" in this region.

Q. Up to this point your analysis has focused on Mr. Frazier's "New England-Mid-Atlantic" market region. Do you have cost data regarding interfuel competition for househeating for the remainder of the United States?

A. Yes. This information is available from the INGAA study for 53 other cities geographically scattered throughout the remainder of the United States. I have summarized the interfuel househeating cost data for the year 1968 only, and they are set out on Schedule 6.

You will notice that this schedule divides the remainder of the United States into three geographic areas—the "Area Around Producing Center," the "Gas Producing Center," and the "Area Assigned to Canadian Growth." These areas are identical with the same geographic breakdown utilized by Mr. Frazier in his Exhibit No. 17.

At this point I would like to make it clear I do not accept these divisions as being meaningful from the viewpoint of supply analysis. For example, I am disturbed by the areas he assigns or does not assign to Canadian growth. I am certain that Northern Natural Gas Co.

would be surprised to see that all of the supply growth for the State of Minnesota must come from Canada, whereas I am sure that Pacific Gas & Electric, Natural Gas Pipeline Co. of America, and the American Natural Gas System would be equally surprised to find that no supply growth can be expected in terms of incremental deliveries from Canada. I find equally incongruous the assignment of New Mexico, the fourth largest producing state in the nation, to the "Area Around Producing Center," while Missouri, with negligible production, is placed in the "Gas Producing Center."

Q. Accepting these as being Mr. Frazier's and not your geographic breakouts, will you please summarize the cost data shown on Schedule 6?

A. Focusing on the "Area Around Producing Center," the cost of gas for househeating in the 1968 season is underpriced comparative to both fuel oil and electricity. The cost of gas househeating averages 66 percent of the cost of fuel oil househeating and 42 percent of the cost of electric househeating.

An even sharper underpricing for gas is noted in the "Gas Producing Center." For 1968 the average cost of househeating by gas was 50 percent of the cost of fuel oil househeating, and 31 percent of the cost of electric househeating.

[1,948]

Gas underpricing is also observed with respect to the "Area Assigned to Canadian Growth." On the average, the cost of gas househeating is 76 percent of the cost of fuel oil househeating and 51 percent of the cost of electric househeating.

In summary, it may be concluded that gas throughout the remainder of the United States is even more underpriced than in the New England-Mid-Atlantic region, and I would agree with Mr. Frazier's testimony that the growth estimates for those areas "are not likely to be materially affected by even severe rate increases in the field price of natural gas." (TR. 1360)

Q. At TR. 1345-1349, Mr. Frazier has also submitted evidence in regard to supply and price of residual fuel oil and coal. Do you agree with his price analysis and forecast of these two fuels?

A. No. I disagree with Mr. Frazier's projections of the price of both residual oil and coal.

Q. Please explain.

A. At TR. 1345 Mr. Frazier comments on the "upward thrust" in price with regard to low-sulfur residual oil. He then states that "wherever this [premium for low-sulfur] differential shakes out, in the next few years,—and it could even go down as desulfurization techniques are perfected—there is no reason to expect a further upward

[1,949]

trend in the visible future."

And with regard to coal, Mr. Frazier (at TR. 1345 states—"Recently, however, a combination of factors has caused marked increases in the delivered cost of coal,"

but "It would be very difficult to foresee a general price trend from this point on, . . ."

I disagree with Mr. Frazier. In my judgment the prices for low-sulfur residual oil and low-sulfur coal will tend to increase in the foreseeable future for much the same reasons they have increased in the recent past.

Q. Please explain.

A. There have been two fundamental factors which have created considerable pressure on prices of low-sulfur residual oil and coal in the recent past. The first factor has been the sustained growth in the economy at a much faster rate than forecast by many. I have previously reviewed this factor in an earlier point in my testimony and its impact on demand and supply of all energy sources.

The second factor which has substantially influenced demands for low-sulfur residual oil and coal, as well as natural gas, has been the rapid advent of air pollution abatement control programs, with respect to sulfur emissions from stationary sources. For at least three years, many forecasters have seriously underestimated the impact of sulfur regulation, especially in the area east of the

Mississippi River. Even now, we are just beginning to feel and understand the impact of this regulation and how it is shifting the demands for various fuels comparative to previous consumption patterns.

Q. What is the status of sulfur regulation from stationary sources in the New England-Mid-Atlantic region?

A. The current status is summarized on Schedule 7. The schedule shows that sulfur oxide control regulations

applicable to fuel combustion sources have been promulgated throughout most of the New England-Mid-Atlantic region.

These regulations are primarily concerned with controlling the sulfur content of bituminous coal and residual oil (Nos. 5 and 6 oil).[4] In examining the maximum allowable sulfur content by weight, the schedule shows a central tendency at 1.0 percent. However, over the next three years New Jersey, New York City, and Philadelphia will cut this level back to 0.3 percent and 0.2 percent.

The schedule also shows that the full impact of these regulations has not yet been felt throughout the region. At this time regulations are in effect in New Jersey, and in the New York City and Washington, D.C.

[1,951]

metropolitan areas. In 1970 regulations will become effective for the remainder of Maryland, in the Boston and Philadelphia metropolitan areas, in New Hampshire, with a further tightening in New Jersey. In 1971 regulations will become effective in Connecticut, with further tightening in New York City, Philadelphia (and also in 1972 and 1973), and in the State of New Jersey.

In summary, it is clear that, to date, the impact of air pollution abatement control on fuel consumption patterns has only partly been felt.

Q. How has air pollution abatement control specifically impacted to date on residual oil?

A. Air pollution abatement control has resulted in an extraordinary demand for low-sulfur residual oil (maxi-

[4] However, a surprising number of regulations restrict the sulfur content of No. 2 fuel oil (househeating oil) and No. 4 oil.

mum of 1 percent sulfur) but has reduced the demand for high-sulfur residual oil. With natural gas in short supply, and low-sulfur coal in short supply, and with no supply relief in sight for either fuel, this demand for low-sulfur residual oil has primarily occurred in PAD District No. I. This situation is compounded by the fact that at this time most, if not all, of the low-sulfur residual oil supplies in the Western Hemisphere have been committed. Reacting to this high demand in relation to supply, the price of low-sulfur residual oil has indeed increased in the recent past.

[1,952]

Q. Have you prepared a schedule showing changes in the price of residual oil in recent months?

A. Yes. Schedule 8 shows changes in the posted price for residual oil (No. 6 oil) for coastal barge deliveries in the New York Harbor over the period 1969 and 1970 to date.

Looking to the upper end of the range in postings shown on this schedule, it is seen that the price of residual oil which is guaranteed to have no more than one percent sulfur has increased progressively from $2.43 per barrel as of October 1, 1969 to $2.48 as of November 3, 1969, to $2.55 as of January 15, 1970, to $2.65 as of April 1, 1970, to $3.00 as of May 3, 1970, to $3.15 as of June 1, 1970, and to $3.25 as of June 8, 1970. Thus, in a matter of nine months, the price of this residual oil has increased 82 cents per barrel, or 34 percent.

Looking at the lower end of the range in postings, the same pattern exists, increasing from $2.38 per barrel as of October 1, 1969 to $3.15 per barrel as of June 8, 1970.

* * * *

[1,964]

PREPARED TESTIMONY OF JOHN M. McCOLLAM

Q. Please state your name and address.

A. My name is John M. McCollam and I live at 1901 Octavia Street, New Orleans, Louisiana.

Q. What is your occupation?

A. I am a practicing attorney and a member of the firm of Gordon, Arata & McCollam, New Orleans, Louisiana.

Q. Would you outline your educational and legal background and your professional experience?

A. I received an A.B. in Economics from the University of North Carolina in 1954 and an L.L.B. from Tulane University School of Law in 1959. I was admitted to practice before the Supreme Court of Louisiana in June 1959, and was subsequently admitted to practice before the United States District Courts for the Eastern and Western Districts of Louisiana and before the United States Court of Appeals for the Fifth Circuit. For two years, while in law school, I was a member of the Board of Editors of the Tulane Law Review and in my senior year served as Editor-in-Chief of that publication. For the past six (6) years, in addition to being engaged in the active practice of law, I have served as Professor of Oil and Gas Law at Tulane University School of Law and will continue to teach that course in the 1970-71 academic year. I have written articles published in the Tulane Law Review and have delivered papers and speeches dealing with various aspects of oil and gas law before the Louisiana Mineral Law Institute, the Mineral Section of the Louisiana State Bar Association and other interested organizations. I am also a member

of the Mineral Sections of the Louisiana State and American Bar Associations.

[1,965]

Upon graduation from law school in 1959, I entered the active practice of law in New Orleans as an associate with the firm of Milling, Saal, Saunders, Benson & Woodward, became a partner of that firm in 1962 and formed my present firm on February 1, 1970.

Since being admitted to the bar I have been chiefly engaged in legal work connected with the oil and gas industry, representing both landowners and producers. My work has included examination of land titles, legal research, preparation of legal proceedings and pleadings, handling of litigation in state and federal courts, drafting, reviewing and negotiations of various contracts such as oil and gas leases, gas sales contracts, unitization agreements, joint operating agreements, farmouts and pipeline permits, as well as rendering legal opinions with respect to problems arising under oil and gas leases and other contracts involved in the day to day conduct of the oil and gas business. I have additionally represented clients, both landowner-lessors and producer-lessees, at numerous hearings before the Louisiana Commission of Conservation and before the Louisiana State Mineral Board.

Q. Did you prepare or cause to be prepared under your supervision and control an exhibit to be uesd in connection with your testimony consisting of Schedules 1, 2, 3, 4, 5 and 6 identified in this proceeding as Exhibit —— (JMM-1)?

A. Yes.

Q. Mr. McCollam, have you read the direct testimony previously given in this proceeding by Dr. Paul David-

son (Tr. pp. 1371-1410), Dr. Charles G. Stalon (Tr. pp. 1209-1289) and Dr. J. Daniel Khazzoom

[1,966]

(Tr. pp. 1291-1325)?

A. Yes.

Q. In particular, have you read that portion of such testimony in which the suggestion is made, principally by Dr. Davidson (Tr. pp. 1388-1392, 1396-1397, 1403-1404 and 1406) that producers, in an effort to justify a higher price for gas and in expectation that an increase in price will be forthcoming, are consciously delaying the exploration, development, production and sale of undiscovered gas reserves thus creating the impression of a gas shortage?

A. Yes.

Q. What is your opinion concerning the suggestion that such conscious delay is occurring?

A. In my opinion that portion of the direct testimony is based on a false premise. To suggest that any responsible producer-lessee would by conscious design delay the prudent exploration, development, production and sale of known and prospective natural gas reserves ignores the stringent legal obligations imposed on a producer-lessee under the usual oil, gas and mineral lease as well as the practical, economic and operational problems inherent in a very competitive industry. These legal obligations give full effect to considerations of prudent operation, which in turn depend on such factors as prices of products, volume of production expected and availability of markets. It would be irrational for producers to pursue the course of action suggested by Dr. Davidson and Dr. Stalon (Tr. p. 1288) for the simple reason that if producers resorted to the tactics suggested they would suffer severe financial

loss due to the forfeiture or cancellation of valuable mineral leases.

Q. Would you please explain that answer?

A. To properly appreciate the issues involved and to place them in their proper perspective, it is essential to understand that the exploration and development of oil and gas properties in the Southern Louisiana Area as in other producing areas, has, with rare exception, occurred under the terms of oil, gas and mineral leases. Such leases are the legal vehicles by which a producer-lessee acquires the right to enter upon the premises to explore for, and if found, to develop, produce and market the oil and gas which may underlie the property described in the lease.

In Louisiana, the "exclusive right" to explore and develop lands for minerals, together with the concomitant right ultimately to produce and market same if found, belongs to the landowner or to a mineral servitude owner, and absent a lease granted by such parties a producer would not have the legal right to do any of these things unless he purchased the land or the mineral rights therein outright.

Q. Would you explain in general the rights acquired and the obligations assumed by an oil and gas lessee in Louisiana?

A. Under the terms of these leases the producer-lessee assumes certain express obligations to the lessor and there is additionally imposed by law, because of the nature of the basic relationship between lessor and lessee, a number of "implied covenants or obligations" which the lessee is bound to discharge, whether or not set out in the lease, on pain of suffering total or partial cancellation of the lease, monetary damages or both.

Prepared Testimony of John M. McCollam

[1,968]

Q. What are the normal fixed considerations which flow to the lessor in an oil and gas lease in return for his granting to the lessee the exclusive right to explore the property described in the lease?

A. As consideration for the initial execution of the lease the lessor is normally paid a certain sum of money, commonly called a "bonus" which maintains the lease in effect for one (1) year from its initial effective date. The amount is normally computed on the basis of so many dollars for each acre covered by the lease and varies with the individual trade and the prospective value of the particular tract. Most mineral leases additionally provide for the payment of an annual "delay rental", also normally computed on an acreage basis, the payment of which will keep the lease in force for additional stipulated one (1) year periods without the necessity of conducting drilling operations. Such rentals can only be paid during a limited time, usually 3 to 5 years, called the "primary term" of the lease, upon the expiration of which the lease can be maintained only by drilling and/or production of oil and gas in paying quantities. The third basic consideration normally accorded a lessor in the usual oil and gas lease is a "lessor's royalty" which is generally expressed in terms of a fractional share of all oil produced and saved from the property subject to lease and a fractional share of the "proceeds" or "market value" of all natural gas produced and sold from the property. I might add that the business of acquiring leases on potentially prospective areas is highly competitive and it is not uncommon for a landowner, once interest has been generated in the area, to have three or four, or more, offers from various parties to lease his property.

* * * *

Q. From the viewpoint of the consumer why would it be disadvantageous for a producer-lessee to lose its lease?

A. Because the ultimate exploration and development of the property would be delayed. The negotiation of new leases and the acquisition of pertinent geological data is always a time consuming and expensive process which in the natural course of events precedes the actual drilling of prospective areas.

Q. Mr. McCollam, you stated that in addition to the usual fixed considerations contained in an oil and gas lease, the lessee also owes to the lessor the performance of certain "implied obligations or covenants" which are enforceable by the lessor whether or not expressly stipulated in the lease instrument. Would you please elaborate on that statement?

A. Yes. I had reference to the implied covenants or obligations which are inferred or implied from the basic lessor-lessee relationship. Broadly stated, there exists in both common law jurisdictions and in Louisiana, where the civil law predominates, an equitable principle to the effect that if the compensation or consideration of one party to a contract depends wholly upon the diligent conduct of the other, the law implies a duty of diligent conduct even in the absence of an express contractual provision.

From this fundamental premise it is reasoned that since an oil and gas lease invests the producer-lessee with the "exclusive" right to drill on the land covered by the lease, and the lessor is contractually rendered powerless to exercise that right, the lessor's reasonable expectation of development of the mineral potential and the monetary

return to be realized therefrom—repeatedly identified by our courts as the principal or primary consideration for granting the lease—should be afforded protection by law.

Q. Will you please specifically identify these implied obligations or covenants as they relate to the lessor-lessee relationship resulting from the execution of an oil and gas lease?

A. The jurisprudence has evolved several well-defined implied obligations. They are:

(1) The obligation to drill additional wells on the leased premises once production is established;

(2) The obligation to protect the leased premises from uncompensated drainage of oil and gas occasioned by wells located on adjoining lands; and

(3) The obligation to produce and market the oil and gas discovered on the leased premises.

The underlying premise of all these obligations is the recognition that pecuniary gain to the lessor—the principal consideration for the lease—depends entirely upon the diligent operation of the leased premises by the producer-lessee. If the lessee permits drainage to occur, this consideration is diminished. If the product once discovered is not marketed, no further consideration is received by the lessor. And, if the lessee fails to diligently explore and develop, the potential of the landowner's property is not fully realized. It has been noted in one Louisiana case that although the concept of implied obligations has been primarily imported into Louisiana case law from common law jurisdiction that

traditional civil law doctrine imposes the same obligations under Article 2710 of the Louisiana Civil Code which obligates the lessee to "enjoy the thing leased as a good administrator".

Q. Would you briefly discuss the principal features of the implied obligations previously mentioned?

A. To facilitate an orderly discussion, I would like to treat each covenant separately and will further comment separately as to the application of those concepts to the three basic types of leases normally encountered in the Southern Louisiana Area, namely, (i) the fee-land lease used by private landowners, (ii) the lease form used by the State of Louisiana to lease its water-bottoms and other state owned lands, and (iii) the lease employed by the Department of Interior to lease federal lands on the outer continental shelf offshore Louisiana.

As the name implies, the obligation to drill additional wells imposes on the producer-lessee the obligation to diligently develop to the fullest extent the horizons which underlie the leased premises. By hypothesis this covenant does not arise until the lease is being maintained by production in paying quantities since prior to that time all drilling, with the exception of off-set wells required to prevent drainage, is excused by the payment of delay rentals during the primary term or by continuous drilling operations.

Once production is established, however, the lessee is not permitted to rest on his laurels. To avoid the risk of judicial cancellation of his lease as to undeveloped areas, the lessee must within a reasonable period of time commence additional drilling operations to further develop

The remainder of the leased premises. He must, in the words of one court, conduct all such operations as would a "reasonably prudent operator in the same or similar circumstances having due regard for the interest of both contracting parties". And, as stated a little differently by another court, "time and prompt development become of the essence of oil and gas contracts once production has been found". No mechanical rule has been formulated by which to apply the "prudent operator" rule or standard because the question of whether the producer-lessee has sufficiently developed the leased property is a question of fact to be resolved by a consideration of the circumstances presented in each particular case. Generally speaking, however, the factors most often considered by the court are (1) time elapsed since date of last drilling; (2) amount of drilling to date; (3) the size of the area covered by the lease; (4) the amount of drilling activity in the general area; (5) the geological information available; (6) the cost of exploratory or development drilling in the area; (7) the reasonable expectation that the new drilling will prove economically successful; and (8) the type and volume of production which can be expected to result.

Of all these factors, the most critical, in my judgment, is the amount of time which has transpired without additional drilling. No hard and fast rule can be stated as to what constitutes a reasonable delay because that is in some measure dependent on the other factors mentioned.

The following brief quotations taken from the jurisprudence at random best express the essence of the rule, viz:

a) *Reagan* v. *Murphy*, 235 La. 629, 105 So. 2d 210, 214 (1958):

"It is the established jurisprudence that full development of the property on which a mineral lease is given is implicit in the lease contract, it being an implied condition of every lease that the lessee will test every part of the land subject to it with reasonable diligence or suffer a partial cancellation."

b) *Hutchinson* v. *Atlas Oil Co.*, 148 La. 540, 87 So. 265, 270 (1921):

". . . time and prompt development become of the essence of such contracts, once oil or gas has been found."

c) *Sauder* v. *Mid-Continent Petroleum Corp.*, 292 U.S. 272, 54 S.Ct. 671, 78 L.Ed. 1255, 93 A.L.R. 454 (1934):

"The justification for the respondent's position is that the geologic data and the experience upon surrounding lands are both unfavorable to the discovery of oil or gas upon the east half of Section 16 (the 320-acre tract). The respondent's officers state that they desire to hold this tract because it may contain oil; but they assert that they have no present intention of drilling at any time in the near or remote future. This attitude does not comport with the obligation to prosecute development with due regard to the interests of the lessor. The production of oil on a small portion of the leased tract cannot justify

the lessee's holding the balance indefinitely and depriving the lessor not only of the

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expected royalty from production pursuant to the lease, but of the privilege of making some other arrangement for availing himself of the mineral content of the land."

Other authorities in point are *Wier* v. *Grubb*, 228 La. 254, 82 So. 2d 1, *Sohio Petroleum Company* v. *Miller*, 237 La. 1013, 112 So. 2d 695 and *Fox Petroleum Co.* v. *Booker*, 123 Okla. 276, 253 Pac. 33, 38, quoted with approval in *Wier* v. *Grubb*, 82 So. 2d 1, 7.

Q. Would you describe what generally happens when a lessor becomes dissatisfied with the exploration and development of his property?

A. Once the landowner has decided that additional development is owed, he will normally make a formal written demand that the lessee either undertake additional drilling within a specified time, normally 30 to 90 days, or give up the lease as to the undeveloped portion thereof. Many of the larger landowners retain geologists who periodically review their properties and make recommendations as to needed exploration or development. The demand may be for additional drilling in undrilled areas of the lease laterally speaking or may be for deeper drilling below shallower producing horizons, or both. Upon receipt of the demand the lessee will normally elect either to (i) undertake the additional drilling, (ii) release the lease as to the undeveloped area, or (iii) advise the lessor that in its opinion no additional drilling is required. In the latter event, litigation almost always ensues. Sometimes in a close case instead of

ordering the lease cancelled as to the undeveloped area of same the court resolves the issue by giving the lessee sixty (60) or ninety (90) days to undertake the additional drilling or to release the lease.

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Q. What remedies are available to lessor because of failure to adequately develop and explore the leased premises?

A. As is apparent from the foregoing discussion, the principal remedy is cancellation of the lease as to the undeveloped portion of same. For example, in one case, *Carter* v. *Arkansas Louisiana Gas Co.*, 213 La. 1028, 36 So. 2d 26 (1948), the leased premises comprised some 1,200 acres and the lessee had drilled two gas wells on the southwest 400 acres of same which were producing in paying quantities thus preserving the entire lease. The lessee refused, however, to drill additional wells on the undeveloped 800 acre portion of the lease on the ground that the available geological information did not justify the risk. After considering all available evidence and in particular the time elapsed since the last well was drilled, the court ordered the lease cancelled as to the undeveloped 800 acres.

Depending on the circumstances the lessee may also be entitled to recover damages and attorneys fees incurred as the result of the lessee's refusal to release the undeveloped portion of the lease.

Q. Would you now discuss the implied obligation to prevent drainage?

A. This obligation is sometimes referred to as the "off-set" obligation, which imposes on a lessee the duty to prevent oil or gas from migrating in the confining

subsurface formation to a producing well located on adjoining lands. In Louisiana, as is true in many common law states, the "rule of capture" prevails. This rule permits an adjoining landowner, or his mineral lessee, by conducting operations on such adjoining lands, to drain oil and gas from beneath the lands of a neighboring

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owner without incurring liability. This frequently occurs where a single reservoir underlines two adjoining tracts, a very common occurrence. The theory is that since neither landowner "owns" the oil and gas as they exist in the subsurface reservoir, either may, by conducting operations on his own land, "capture" the oil and gas by reducing it to possession at the wellhead and thus become its owner. This is similar to the law applied with respect to wild animals which belong to no one until killed or captured by some individual who thereby becomes the owner. Because of this rule it is an implied obligation of all mineral leases that the lessee, by the drilling of "off-set" wells, must prevent such migration of hydrocarbons or drainage from the leased premises. This covenant, unlike the development obligation, is equally applicable both before and after production is established on the leased premises because it involves the protection of the premises against a permanent loss of value.

Again, under Louisiana law, the lessor, as a required prerequisite to instituting suit based on the violation of this obligation is obliged to make a formal demand on his lessee that the off-set will be drilled. But once that demand is made, if the potential drainage is subsequently proved, the off-set well is shown to be reasonably eco-

nomic, and lessee has not drilled the necessary off-set well or initiated unitization proceedings to insure lessor a fair share of the reservoir content, the lessor is entitled to (i) cancellation of the lease and (ii) damages for all losses suffered as the result of such drainage subsequent to the date of demand.

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In a recent Louisiana case the court indicated that the amount of damages recoverable by a lessor in a drainage situation is either (i) the amount of royalty which the off-set well would have produced for lessor if it had been timely drilled, (ii) the actual value of the lost hydrocarbons if this can be shown, or (iii) the cost the lessee would have incurred in drilling the off-set well.

Q. Dr. Davidson (Tr. pp. 1382, 1388-1392, 1395-1396) and Dr. Stalon (Tr. pp. 1288-1289) have suggested that producers might withhold production from the market in order to take advantage of an anticipated increase in the price of gas. In the context of that suggestion, would you please discuss the implied obligation to market oil and gas once found?

A. Their suggestion is indefensible because the producer cannot delay production if a reasonable market is available. Again the underlying rule is that the lessee must operate the leased premises as a prudent administrator for the mutual benefit of lessor and lessee and is obligated to market the production at the best market price available, assuming there is a market. Actually, there is very little litigation on this point for several reasons. First and foremost is the fact that the lessee is anxious to begin receiving revenues. Secondly, because of the fact that a great many producing wells, both

oil and gas, are more often than not completed in reservoirs from which other producers are also producing, curtailment of production would mean a monetary loss to the producer because of drainage. And thirdly, if production in paying quantities ceases for sixty or ninety days, depending on the lease terms, the lessee may lose the lease. Although most leases provide with respect

to gas wells that the wells may be shut-in and the lease maintained by the payment of shut-in rentals or royalties for a limited period of time, these payments are normally equal to the delay rentals stipulated in the lease and cannot be recouped out of subsequent production. Leaving aside the legal prohibition, at today's rental prices there is therefore a very real economic deterrent to using shut-in rentals unless there is in fact no market.

Q. Mr. McCollam, you stated that with respect to gas wells, as opposed to oil wells, most modern lease forms permit the payment for stipulated periods of "shut-in royalties or rentals" in lieu of the actual production of the well, and I want to ask you are there any limitations on the lessee's right to rely on such payments to maintain the lease?

A. Yes, there are several. To understand the reason for the most basic limitation—the required non-availability of a market—it is helpful to be familiar with the manner in which the shut-in royalty or rental clause evolved. Historically, and as a matter of demonstrated fact, it is much easier to market oil than gas. Oil can be economically taken to market by pipeline or in lieu thereof by truck or barge, hence there was seldom, if ever, real need to shut-in an oil well over a prolonged

period. This was not true of gas, however, which can only be economically transported via a system of expensive and complex gathering and transmission pipelines.

During the 1930's, 40's and early 50's, prior to the development of the pipeline network now existing and still expanding in Louisiana, it

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was not uncommon for an operator to drill a producing gas well and have no market for same. And if gas was produced along with oil from an associated reservoir it was normally flared. In response to this situation, there began to be included in lease forms shut-in royalty clauses which traditionally permitted gas wells, upon the payment of a stipulated sum, to be shut-in until a market became available. This language is critical and in one context or another now appears in all shut-in rental or royalty clauses such as that annexed hereto as Schedule 1 of my Exhibit. Thus, if a market for the gas is reasonably available, always a question of fact, shut-in royalties cannot be used to maintain the lease. The well or wells must in those circumstances be produced. Additionally, most shut-in clauses with which I have had any experience specifically limit the time within which they may be used to maintain the lease, generally to a three (3) or five (5) year period, with payments on a periodic basis.

Q. Does that conclude your general discussion of the implied obligations inherent in an oil and gas lease?

A. Yes, it does. I should also observe that although the entire foregoing discussion was oriented primarily toward the usual fee-lands lease, the lessee's obligations

with respect to state and federal leases are, if anything, even more stringent, as will be apparent from my subsequent testimony.

Q. Before moving on to a consideration of state and federal leases, I want to ask you if it is true that some lease forms now in use in Southern Louisiana, particularly those employed by large landowners,

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impose express development and offset obligations on the lessee in addition to those implied by law?

A. Yes, that is quite true. It is not at all unusual for a lease form, such as that attached as Schedule 2 of my Exhibit, to impose on the lessee a "continuous drilling or operations" obligation which compels the lessee to either drill a well every 90 or 180 days or suffer a loss of the lease as to all areas except a designated portion around each producing well. Some lease forms additionally provide that the acreaage to be retained around each producing well must be released as to all depths 100 feet or more below the total depth of the producing well.

Q. With a lease form of that kind, is it fair to say that there can be no delay in the development of the leased premises if the lessee is to retain the lease?

A. That is correct. If the required drilling schedule is not met the lessee automatically loses its leasehold rights as to the undeveloped portions of the lease. I might add that these leases generally also impose much more onerous bonus, rental and royalty payments than do leases granted by smaller landowners. By virtue of having control of large contiguous areas the big landowners, and I include the federal and state governments in this category, are, generally speaking, in a superior

bargaining position with a prospective lessee who likes to lease as much acreage as possible in an area deemed potential for oil and gas production.

Q. Do you have any figures as to the percentages of lands which are held under this "large landowner" type of lease in Southern Louisiana?

A. No, I do not, but I would estimate that it is substantial,

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perhaps as much as 50% of the onshore acreage under lease. I know for example that in Docket No. AR61-2, William W. Westerfield, Jr. (Tr. p. 2254) testified that of the onshore acreage held by Shell Oil Company as of January 1, 1963, 54.5% was held under forms used by the large landowners (defined as those owning 1,000 acres or more in the prospective area) and I would expect that to be a fairly representative figure with respect to other major operators.

Q. Turning now to oil and gas leases granted by the State of Louisiana on state owned waterbottoms and other state owned lands, would you explain how those leases come to be executed?

A. Under Louisiana Revised Statutes of 1950, 30:121 et seq. the State Mineral Board is given the authority to execute leases on state owned lands by a method of sealed competitive bids after public advertising subject to various other statutory requirements. One of the statutory requirements is a minimum royalty of one-eighth (1/8th) of all minerals produced. As a matter of actual fact, however, the royalty is always one-sixth (1/6th) or more. Additionally, no lease can be for more than 5,000 acres and none may be granted for less bonus and delay rental than was offered in the most favorable

written bid for the same property. Moreover, where a lease provides for an annual delay rental, which is the usual case, the annual rental must not be for less than one-half the cash bonus. This latter clause often has the effect of compelling the lessee to drill within the first year of the primary term of the lease since it would not be economic to postpone operations and have to pay a large rental which is usually high because of the necessity of bidding a top dollar bonus to

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acquire the lease in the first place. I have attached hereto as Schedule 3 of my Exhibit a copy of the state lease form in current use.

Q. After execution of a state lease, is the lease supervised by anyone for the state?

A. Yes, and the supervision is very efficient and effective. Under the statute all bonuses, rentals, royalties, shut-in payments or other sums payable to the state are paid to the Register of the State Land Office, but the authority for supervision of the leases once granted continues to vest in the State Mineral Board. It is specifically authorized to take any action deemed necessary to insure compliance with the leases granted, including the right to institute judicial proceedings to annul a lease for the violation of lessor's rights thereunder.

Q. Are the implied obligations or covenants which you have discussed previously with respect to fee-land leases generally applicable to leases granted by the State of Louisiana?

A. Yes, definitely, and the State Mineral Board, through its Fact Finding Committee, has devised an extremely efficient method for insuring compliance with

those obligations. Unlike many large landowner leases, the state form, with the exception of several specific offset drilling requirements, does not prescribe fixed drilling obligations. The Board early in its history adopted a philosophy of maintaining maximum flexibility as to operations expected of its lessees and chose instead to rely on the generally implied obligations, diligently enforced by the Fact Finding Committee and its supporting staff of highly trained technical personnel.

[1,987]

Q. Can you explain the make-up, function and purpose of the Fact Finding Committee of the State Mineral Board?

A. The Fact Finding Committee is comprised of six (6) members of the seventeen (17) man State Mineral Board. This committee generally meets for a two (2) day period a minimum of once per month for the express purpose of (i) reviewing recommendations made to it by the technical staff of the Mineral Board, which consists of eight (8) petroleum geologists and three (3) petroleum engineers, concerning operations which should be required under state leases, and (ii) to discuss with representatives of various producer-lessees demands made as the result of recommendations adopted at the previous month's meeting.

Q. Does the Technical Staff of the Mineral Board have any particular method by which it reviews state leases maintained by production?

A. Yes. The state is divided into four (4) areas and a district geologist is charged with the responsibility of reviewing all leases in his district, at least once annaully, and sometimes much more often, where the possibility

of drainage is likely because of fragmented ownership. Such review may result in notice to the producer-lessee inviting him to attend the next monthly meeting of the Fact Finding Committee at which time he will be expected to present in detail his future exploration and development plans for the lease. I have attached as Schedule 4 of my Exhibit a sample of one of these notices from which the names of the particular producers involved have been deleted. If the Fact Finding Committee is not satisfied with the pace of development, the matter is turned over to the Legal Department of the Board for review. This usually

results in a formal legal demand for exploration and development followed by lease cancellation litigation in the event the producer-lessee continues to refuse to drill or to release the lease. Attached as Schedule 5 of my Exhibit is a copy of a representative demand letter from which I have again deleted the names of the producers involved. Such litigation occurs on only limited occasions because most responsible operators will either undertake the required additional drilling or give up the lease.

Q. Is the procedure employed by the Fact Finding Committee and staff any different where drainage is a possibility?

A. Yes, in that circumstance the whole process is speeded up and the time periods accorded for additional drilling are much more restricted. For example, if the staff on reviewing any one of the several commercial weekly scouting reports subscribed to by the Mineral Board ascertains that a new producing well has been completed on a land area adjacent to a state owned

waterbottom lease and that there is a possibility that drainage may occur, the state-lessee is immediately sent a notice requiring that he appear before the Fact Finding Committee and either (i) demonstrate geologically to the satisfaction of the staff that drainage will not occur, (ii) advise the Committee of its plans to drill the necessary off-set well or to institute the necessary unitization proceeding before the Louisiana Department of Conservation to insure the State its fair share of reservoir content, or (iii) in lieu of drilling an off-set well agrees to pay a compensatory non-recoupable lieu royalty computed on one-half of the production from the potentially draining well.

Q. Does the Fact Finding Committee concern itself with the implied

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obligation to market oil and gas once same have been discovered?

A. Yes, it does. The state lease form, like other leases, permits the lease to be maintained by the payment of semi-annual shut-in rentals if there is located on the property covered by the lease, or on lands unitized therewith, a well or wells capable of producing gas in paying quantities and gas is not being used or sold "because of the lack of a reasonable market or marketing facilities or governmental restrictions. . . ." Again, as is the case with most fee-lands leases, this clause can only be utilized where there is no available reasonable market, and the Lieu Royalty Committee, as a matter of course, reviews each lease being maintained by shut-in rentals every six (6) months to determine if a reasonable market has become available. And, with the expanding network of interstate pipelines and the burgeoning intrastate market

created by the rapidly advancing industrialization along the Mississippi River, it is becoming unusual for there to be no market. As a matter of fact, gas purchasers are now very aggressive in Louisiana and a lessee often has two or three market outlets from which to choose.

Q. Is it then fair to say that the State Mineral Board, through its Fact Finding Committee, Lieu Royalty Committee, and supporting staff, faithfully exercises its supervisory authority to require diligence in the exploration and development of state leases and in the marketing of oil and gas discovered thereon?

A. Without question. In this connection it is worthy of note that in the budget year 1968 revenues derived by the state from bonuses, rentals, royalties and state severance taxes on oil and gas accounted

for some 46% of the entire state budget of almost one billion dollars. When you realize that Louisiana, like most other states, municipal governments and the federal government, has more demands for funds than it has revenues, I think you can appreciate why, among other reasons, the State Mineral Board is most careful to maintain by systematic surveillance the required exploration and development of its mineral properties.

Q. Considering the economic importance of mineral revenue to the state, what in your opinion would happen if a mineral lessee refused or failed to pay the bonus, rental and royalties due under a state lease?

A. He would lose the lease either as the result of a termination under its own terms or via cancellation litigation depending on the nature of the consideration not paid.

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Prepared Testimony of John M. McCollam

Q. Mr. McCollam, is the State lease form at Schedule 3 of your Exhibit also used with respect to any offshore waterbottoms?

A. Yes, it is. Although leasing in the contested zones (Zones 2 & 3) of the outer continental shelf in the Gulf of Mexico is conducted by the federal government, the Interim Agreement of 1956 executed by the State of Louisiana and the United States pursuant to the Submerged Lands Act, provides that the state has the authority to grant leases in Zone 1, which covers an area, at a minimum, thought to be within three (3) miles seaward of the Louisiana "coastline", a demarcation line not yet established and still in litigation.

Q. Would you now discuss the granting of oil and gas leases by the federal government in the Southern Louisiana Area on offshore waterbottoms located on the outer continental shelf in the Gulf of Mexico?

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A. Under the Interim Agreement of 1956, the federal government has the right to grant oil, gas and mineral leases on all areas lying in Zones 2, 3 and 4 of the offshore area as same are defined in the Interim Agreement. The leasing of these waterbottoms, commonly referred to as outer continental shelf lands, is governed by the Outer Continental Shelf Lands Act (43 U.S.C. 1331, et seq.). Such lands are defined in the Act as those lands lying seaward of the area ceded to the coastal states by the United States in the Submerged Lands Act (43 U.S.C. 1311) which established maximum and minimum distances of these boundaries from the coastlines of the respective states.

Under Sections 5 and 8 of the Outer Continental Shelf Lands Act the authority to administer the outer conti-

nental shelf lands, and to grant oil and gas leases thereon, is vested by law in the Secretary of the Interior (Secretary), and the Secretary in turn has issued extensive leasing and operating regulations which are found in 30 C.F.R. 250 et seq., 43 C.F.R. 2234 5-3 and 43 C.F.R. 3380 et seq. The Secretary by Executive Order No. 2583, as amended on September 17, 1954, delegated to the Director of the Bureau of Land Management (Director) the principal authority to take all necesary action with respect to the leasing and supervision of outer continental shelf lands. Additionally, many specific delegations appear in the regulations where the Director, rather than the Secretary, is authorized to perform specific acts. The Director has also delegated much of his authority to other agencies of the Department of the Interior. Under the regulations, however, subject to the supervisory jurisdiction of the Secretary and Director, once an oil and gas lease has been granted,

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it is fair to say that the Oil and Gas Supervisor of the United States Geological Survey (USGS) has the day-to-day authority to supervise operations under the lease and to collect rentals (exclusive of that due the first year) and royalties.

Q. What is the procedure for obtaining a federal lease on outer continental shelf lands?

A. Section 8 of the Outer Continental Shelf Lands Act provides that all such leases shall be issued on a competitive basis to the highest responsible qualified bidder at a public letting by sealed bids in accordance with rules and regualtions to be promulgated by the Secretary which, among other things, require extensive publication in the Federal Register and elsewhere. Such lettings are com-

monly held only when the Secretary and Director have determined that sufficient interest has been evidenced by operators to justify holding a sale. The Act limits the number of acres which can be committed under one lease to 5,760 acres, but in general practice a lease covers 5,000 acres because of the system employed in surveying these lands. Additionally, by statutory limitation a lease may not be granted for a longer primary term than five (5) years.

Q What fixed considerations flow to the lessor under federal leases?

A. Under Section 8 of the Outer Continental Shelf Lands Act, when outer continental shelf lands are offered for lease, the bidding, at the discretion of the Secretary, may either be on the basis of a cash bonus with a fixed royalty of not less than 12.5% or on the basis of a royalty not below the specified statutory minimum of 12.5% with a cash bonus as

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previously fixed by the Secretary. Insofar as I am aware, all or the great majority of leases issued to date have been on the basis of a competitive cash bonus and the royalty has been fixed at one-sixth (1/6th). Traditionally, the offer to lease published by the Secretary also stipulates the annual rental which may be paid to maintain the lease during the primary term in lieu of drilling. To date in Southern Louisiana this has been set at $3.00 per acre. The lease form now in use also provides that once production has been established a minimum dollar royalty, to be fixed by the Secretary, shall be paid and if royalty on actual production is less than this amount, expressed in terms of a certain sum per acre, the lessee must make up the difference.

Q. Do you have a copy of the lease form currently in use to lease outer continental shelf lands?

A. Yes. I have attached a copy hereto identified as Schedule 6 of my Exhibit.

Q. Would you briefly analyze the principal terms of the lease with particular emphasis on the obligations imposed on the lessee thereunder?

A. Sections 1 and 4 of the lease grant to the lessee the exclusive right to explore the property described for a primary term of five (5) years and so long thereafter as oil or gas may be produced therefrom in paying quantities, or drilling and reworking operations, as may be approved by the Secretary, are conducted thereon. As noted previously, the five (5) year term is set by statute, 43 U.S.C. 1337 (b) (2), and by the regulations, 43 C.F.R. Sec. 3382. 2(a). Section 3(a) of the lease requires the lessee to pay the annual rental, the minimum royalty and the royalty when due.

Q. What would happen if the bonus, rentals and royalties stipulated in the lease were not paid when due?

A. The lessee would either (i) never obtain an enforceable lease, or (ii) lose the lease under one of the two appropriate cancellation procedures which will be discussed subsequently. In this connection it is worthy of note that the regulations provide that one-fifth of the bonus bid on a tract must accompany the bid (43 C.F.R. 3382.4).

Q. Please continue with your discussion of the lease provisions.

A. The next section of the lease which should be discussed in the context of this testimony is Section 3(c) which spells out the drilling obligations imposed on the

lessee. The provisions of the lease in this respect for the most part mirror the pertinent regulations, *i.e.*, 43 C.F.R. 3387.3-2(a), 3387.3-2(c) an 3387.3-4 and 30 C.F.R. 250.33(a), 250.33(b) and 30 C.F.R. 250.34 and 250.35. Under Section 3(c)(1) of the lease the lessee is required:

> "To diligently drill and produce such wells as are necessary to protect the lessor from loss by reason of production on other properties or in lieu thereof, with the consent of the Supervisor, to pay a sum determined by the Supervisor as adequate to compensate the lessor for failure to drill and produce any such well."

Q. Mr. McCollam, does the provision just quoted correspond to any of the implied obligations which you have testified arise under the usual fee-lands lease and the lease form utilized by the State of Louisiana?

A. Yes, it is in effect an express statement of the implied

covenant to prevent drainage by the drilling of off-set wells.

Q. Does the federal lease form contain an express provision corresponding to the implied obligation to develop?

A. Yes. Section 3(c)(2) of the lease requires the lessee:

> "After due notice in writing to diligently drill and produce such other wells as the Secretary may reasonably require in order that the leased area or any part thereof may be properly and timely developed and produced in accordance with good operating practices."

Prepared Testimony of John M. McCollam

Q. What remedies are available to the United States in the event the lessee fails to comply with any provision of the lease, the Outer Continental Shelf Lands Act or the pertinent regulations?

A. The lease is subject to cancellation. Under Section 5(b) of the Outer Continental Shelf Lands Act, 43 C.F.R. 3386.2, 30 C.F.R. 250.80, 250.81 and 250.82 and Section 10 of the lease, the Secretary, upon the giving of a thirty (30) day notice of default is authorized to cancel non-producing leases, subject to judicial review. And in the instance of a producing lease, it may be cancelled by appropriate proceeding before the United States District Court having jurisdiction. As noted previously, the lessor also has the right to invoke any other legal or equitable remedies available which may include the right to assert the forfeiture of the lease and a claim for monetary damages, or both, in the event a violation of the implied obligations can be shown.

Q. In your opinion what would happen if the lessee of a federal lease failed to diligently explore, develop and protect the premises

subject to the lease?

A. Although I know of no case in point, primarily because the producers of which I have any knowledge are always striving to complete development as rapidly as possible in order to begin to recoup the high bonuses and other investment costs previously incurred, I would expect the leases to be cancelled if the thirty (30) day demand is not heeded. In this respect the federal leases are no different from the fee-lands leases or the state lease as regard the obligations of the lessee.

Q. What about the implied obligation to market once production is established on a federal lease?

A. Again the same general rules apply and, unless a reasonable market is not available, the lessee must produce the well. In this connection, cognizance should be taken of Special O.C.S. Order No. 4 dated August 28, 1969, issued by the Supervisor pursuant to 30 C.F.R. 250.11 and 250.12 which permits the extension of a lease beyond its primary term even in the absence of actual production, where transportation facilities are not available to market the product, or a well capable of producing has been abandoned temporarily to facilitate proper development by the construction of a platform or otherwise. Under O.C.S. Order No. 4 the Supervisor may approve a suspension of production and extension of the lease provided at least one well has been drilled on the lease and determined to be capable of being produced in paying quantities. The order thereafter sets out fairly detailed criteria which must be met in order for the well to qualify as a well capable of producing in paying quantities. During the period of such suspension, the lessee must continue to

pay rental or minimum royalty fixed at the discretion of the Supervisor and such payments may not be recouped out of subsequent production royalties.

Q. Is it then fair to say that the basic obligations imposed on the lessee under a federal lease covering outer continental shelf lands are not materially different from those which arise under the ordinary fee-lands lease and the lease used by the State of Louisiana?

A. Yes.

Q. Mr. McCollam, did you review the direct testimony previously given herein by Dr. J. Daniel Khazzoom (Tr.

pp. 1323-1325) in which it was suggested that "new field discoveries" in offshore Louisiana should be exempt from royalty payments to the Department of the Interior?

A. Yes, I am familiar with the testimony to which you refer.

Q. What would be required in order to comply with Dr. Khazzoom's recommendation?

A. As I understand his testimony, Dr. Khazzoom implies that the exemption of such royalties should be a prerogative available to the Federal Power Commission, a point which I am not prepared to debate. I think it must be clearly understood, however, that the assumption of such authority by the Commission cannot be accomplished by mere administrative or executive action and that it would necessitate an Act of Congress amendatory to the Outer Continental Shelf Lands Act to accomplish that objective. That is so because Section 5 of the Act clearly vests in the Secretary of the Interior full authority for the administration of the provisions of the Act relative to the leasing of the outer continental

shelf lands and further specifically (43 U.S.C. 1337(a)(2) and 1337(b)(3)) makes it mandatory that all such leases provide for a royalty on all oil and gas of not less than 12.5% of the amount or value produced. This statutory minimum royalty clearly could not be waived without congressional action.

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[2,008]

BEFORE THE FEDERAL POWER COMMISSION

IN THE MATTER OF

AREA RATE PROCEEDING, *et al.*
(OFFSHORE SOUTHERN LOUSIANA
FEDERAL DOMAIN AND DISPUTED AREAS)

Docket No. AR69-1, *et al.*

PROPOSED TESTIMONY OF CHARLES A. LARSON

Q. Please state your name and address and describe your business affiliation.

A. My name is Charles A. Larson, I am Vice President and Director of the Regulatory Services Division of Commonwealth Management Consultants, a division of Commonwealth Services Inc. Our offices are at 1250 Connecticut Avenue, Washington, D. C. 20036. Commonwealth, affiliated with Computer Sciences Corporation since February 27, 1970, is a widely diversified, international organization with experience background of more than sixty years as consultants in all phases of management, engineering, architecture and transportation services for public utilities, industrial organizations, government agencies and other institutions.

Computer Sciences Corporation is one of the leading companies in the field of information sciences. CSC

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provides industry and government with a broad range of technical services including computer system programming; management of computer facilities; systems engi-

neering for communication networks; implementation of military command and control systems; development of scientific programs for the aerospace and nuclear fields; and consulting services in the oceanography, geophysics and urban planning fields.

Q. What are your responsibilities as Director of the Regulatory Services Division of Commonwealth?

A. My responsibilities, as Manager of the Regulatory Services Division, are directed to the consulting services in regard to matters concerning government and business. Some of the services rendered by my division are (1) rate design, (2) cost of service, (3) forecasting, (4) load research, (5) rate of return, (6) rate base valuation, (7) energy research, (8) cost allocation, (9) marketing, and (10) computerized model building.

Q. What is your most recent service regarding computerized model building?

A. Recently, I conducted a seminar at the University of Wisconsin sponsored by the American Gas Association.

[2,010]

The seminar, which was a part of a course on gas rate fundamentals, dealt with the construction of a computerized forecasting model for a gas distribution utility. The sub-models discussed were (1) marketing, (2) Ogive, (3) systems planning, and (4) financial.

Q. Are you familiar with the current gas supply problems?

A. Yes, since Commonwealth has assisted several clients in regard to their natural gas supply, I have studied pipeline gas supply, gas storage, gasification of coal, Canadian gas supply, and liquified natural gas (LNG) supply both from pipelines and from abroad.

Q. What are your educational qualifications?

[2,010]

Proposed Testimony of Charles A. Larson

A. I received the degree of Bachelor of Science in Electrical Engineering in 1948 from the University of Wisconsin. In 1950 I received a Master's Degree in Business Administration in public utility economics from the University of Wisconsin's Graduate School of Business. I did graduate study in accounting at the Graduate School of Business at the University of Denver. At the Graduate School of Business of New York University I did graduate study in economics, statistics and finance.

Q. Are you a member of any professional associations?

[2,011]

A. I am a member of the following professional associations:

American Finance Association
Southern Gas Association
Southern Economic Association
National Accounting Association
Society of Petroleum Engineers
American Association of Cost Engineers
American Economic Association

Q. Were you in the military service?

A. Yes, during World War II, I was a Naval Officer assigned to air intelligence with a research and development task force.

Q. What was your first professional experience?

A. I was a systems study engineer with the Wisconsin Electric Cooperative from 1948 to 1950. My economic-engineering duties were to make economic feasibility studies of rural electric distribution systems in Western and Northern Wisconsin.

Q. When did you begin your management consulting experience?

Proposed Testimony of Charles A. Larson

A. In 1950, I joined the firm of Middle West Service Company in Chicago, Illinois. This firm was engaged in management and engineering consultation to gas and electric utility companies.

Q. What were your responsibilities in that firm?

[2,012]

A. My responsibilities were primarily directed to the preparation of financial, rate and cost analysis. In this capacity I prepared financial statements and made economic forecasts, designed rates and prepared costs of service for numerous gas and electric utilities.

Q. Have you had previous experience in the operations and management of a utility company?

A. Yes, in 1954 I became a Rate Analyst with Public Service Company of Colorado in Denver, Colorado. This firm is a combination utility which sells gas and electricity in the various counties of Colorado. In addition, it provides steam heating service in the City and County of Denver, Colorado and bus service in the City of Boulder, Colorado. I worked in the Department of Rates, Real Estate and Property Accounting in the Accounting Division. My responsibilities included (1) analysis of financial statements, (2) preparation of costs of service, (3) rate design, (4) supervision of the gathering of rate statistics, and (5) review of customer contracts and rules and regulations for gas, electric, steam and bus customers.

Q. Have you had experience as an economist?

[2,013]

A. Yes. From 1957 to 1959, I was an economist for the Edison Electric Institute in New York City. EEI

is a trade association for the electric utility companies.

Q. What were your responsibilities with EEI?

A. I was responsible for economic studies of the electric industry including forecasts, taxes, executive compensation and energy competition. I represented the Staff at meetings of the Rate Research Committee.

Q. Did you have additional experience before joining Commonwealth Management Consultants?

A. From 1959 to 1968, I was a Senior Consultant with National Economic Research Associates, Inc. in New York City, a firm of consulting economists.

Q. What were your responsibilities for that firm?

A. I was responsible, primarily, for analyzing the cost of finding, producing, gathering processing, transmission and distribution of natural gas. Additionally, I made financial studies of large integrated oil companies.

Q. Have you testified before the Federal Power Commission?

A. Yes. I prepared numerous cost and financial studies in cases involving natural gas companies and have appeared as a witness on numerous occasions before the Federal Power Commission.

Q. Before what State Commissions have you appeared as an expert witness?

A. I have testified before the State Commissions in Connecticut, Massachusetts, Virginia, and West Virginia.

Q. Have you testified in the area rate proceedings of the Federal Power Commission?

A. Yes. I have testified in the following area rate proceedings: Southern Louisiana, Docket No. AR61-2, *et al.;* Hugoton-Anadarko, Docket No. AR64-1, *et al.;* Texas Gulf Coast, Docket No. AR64-2, *et al.;* and Other South-

west, Docket No. AR67-1, *et al.* Additionally, I testified in the Pipeline Production Area Rate Proceeding, Docket No. RP66-24.

Q. Have you ever testified before a court?

A. Yes. I appeared as a witness presenting financial statements before the Federal District Court in *United States of America* vs. *El Paso Natural Gas Company*, C-143-57.

[2,015]

Q. What is the nature of your testimony, Mr. Larson?

A. I have been asked by the United Distribution Companies (UDC), Intervenors in these proceedings, to rebut portions of the testimony of Mr. Charles H. Frazier.

More specifically, I am in disagreement with Mr. Frazier with respect to his conclusions that (1) price rises will have a significant impact on demand for gas in the general area served by the AGD companies, (2) the rest of the nation can more readily absorb large increases in the wellhead price of gas in South Louisiana, and (3) a multiplier effect causes the impact of a wellhead price increase of one cent to produce a two cent increase at the retail level in New England.

Q. Before getting into a discussion of your specific differences with Mr. Frazier, do you have some general comments to make regarding price elasticity in the gas industry?

A. Yes. I will make an observation regarding price elasticity that will serve as a general background for most of my testimony. It is generally recognized that the residential market is the most inelastic of the major market classes. This is so because gas is held in very high regard by the residential consumer because

[2,016]

of its cleanliness and trouble free service. Accordingly, gas can be at a price disadvantage and still capture a large share of both new homes and conversions as homeowners replace obsolete units. On the other hand, the gas residential customer is unlikely to change to a different fuel, unless there is a major cost saving. A commercial customer is usually willing to pay a slight premium for a convenience fuel and will resist change to another fuel unless the price advantage is large. Still, the commercial market can be considered generally more price elastic than the residential market. Finally, in the industrial market elasticity ranges from very high to very low. Industrial users with facilities to use other fuels will pay almost no premium for gas, other things being equal, and will shift large loads to another fuel anytime the cost of gas becomes higher than the other fuel. Other industrial customers are in a situation where only the cost of installing facilities would keep them from switching to coal or oil as the price of gas increases. Large users, such as steel mills in the midwest, are generally in this situation and a small unit difference on these large loads can justify large capital expenditures that may be involved in the conversions.

[2,017]

Finally, some industrials, such as the glass industry, will pay premium prices for gas because of the need to maintain uniform temperatures.

Q. Have you prepared an exhibit setting forth the basis for your analysis of Mr. Frazier's testimony?

A. Yes. Exhibit 37 was prepared by me and by my employees working under my supervision.

Q. Please describe your objection to Mr. Frazier's conclusion that price rises will have a significant impact on demand in areas in which the AGD companies operate.

A. Please refer to Schedule No. 1 of my exhibit. This schedule shows that in Region 1 (New England) the residential load is 53.8 per cent of the total load (the highest in the nation) while in Region 2 the ratio is 41.3 per cent, the next highest. Further, the percentage of residential load of the AGD companies operating in Region 2 is higher than the total for the region. Therefore, it appears that the residential market is approximately half of the total market for the AGD companies. Schedule 1 also shows that the commercial market in Regions 1 and 2 is proportionately higher than for the rest of the nation. The industrial market,

[2,018]

as can be expected, is proportionately less than in other regions of the country. This analysis indicates that the existing loads of the AGD companies operating in Region 1 and the Eastern part of Region 2 are less price elastic than the loads in the other FRC regions.

Q. Have you made an analysis of the growth record of the AGD companies?

A. Yes. I have analyzed the actual experience as reported in the FRC report where possible. However, there is not sufficient information in the FRC report to meet the various contentions of Mr. Frazier. Therefore, I have collected certain information from the state regulatory commissions and other sources and have used this information in conjunction with the historical information in the FRC report.

Q. Please describe this analysis and explain its significance.

[2,018]

Proposed Testimony of Charles A. Larson

A. Schedule 2 of my exhibit compares the growth rates of the various AGD companies with those for the nation in total. This schedule shows, contrary to Mr. Frazier's implication (Tr. 1336), that the growth rates of the AGD companies have been substantially greater than those for the rest of the nation, both in the residential

[2,019]

market and in the total market. For the residential segment, AGD companies show the really remarkable growth rate of 5.44 per cent as compared with 4.12 per cent for the rest of the nation. This high growth rate is the result of the low space heating saturation in the AGD companies' areas and the desire of the consumers in general to switch to a more desirable type of fuel when they replace heating systems in their homes. The potential for continual growth in the residential market leads to the conclusion that the AGD companies are no more apt to be place in jeopardy by wellhead price increases than are companies in other areas.

Q. Do you have a further comment on Mr. Frazier's Schedule No. 4, which shows a comparison of space heating saturations and the corresponding oil/gas price ratio, and on his conclusion (Tr. 1352) that: "It is clear from these data that gas sales for home-heating *are* price elastic."?

A. I believe that Mr. Frazier has misapplied these data. The relatively low space heating saturation in the areas in which AGD companies operate is a function of the relatively short time during which this area has had natural gas. The Philadelphia-New York-New England area

[2,020]

has had natural gas in substantial quantities only since the early Fifties whereas the Appalachian area has had natural gas since the turn of the century and the Gulf Coast area has had natural gas since the early 1920's.

The space heating saturation in the AGD companies' operating areas is rising rapidly. As shown on my Schedule 3, the saturation of the AGD companies rose from 31 per cent to 43.2 per cent during the period 1961-1968, as compared with the relatively modest increase from 79.2 per cent to 86.9 per cent for the rest of the nation.

Q. Are you familiar with the pricing policies of gas distribution companies in the New England-Eastern Seaboard area?

A. Yes. I have recently participated in gas rate proceedings in Connecticut and Massachusetts, two states that qualify as being a great distance from the Gulf Coast.

The proceedings to which I referred are (1) Connecticut Natural Gas Corporation, Docket No. 10833, and (2) The Berkshire Gas Company, D.P.U. No. 16597.

[2,021]

Q. Will you please describe how each of these companies reflected cost increases in the design of their rates?

A. Each company found that substantial rate increases were necessary and was able to design such increases in a manner that would provide greater revenues without affecting future prospects. The residential rates for each of these companies were increased more than 15 percent. As a point of contrast, a 5-cent increase in the wellhead price would constitute only a 2.5 per cent

increase to the average residential customer in Boston. The distributing companies and pipeline companies with which I am familiar are experiencing increased costs of operation, for which adjustments are necessary. If the markets served by these companies are sufficiently inelastic to permit these increases, I cannot see how they suddenly become price elastic when we talk about increased prices at the wellhead.

Q. Please summarize your disagreement with Mr. Frazier's conclusion that price rises will have a significant impact on demand in the areas in which the AGD companies operate.

A. These AGD companies have excellent growth potential in the high end use segments of the market and, while price

[2,022]

increases are to be avoided wherever possible, I am convinced that a gas supply shortage will be far more detrimental to both the consumers and to the growth prospects of such companies than will the price increases that Mr. Frazier has assumed in his testimony. To the extent that increased prices might mean a slowdown in growth for the AGD companies, this will probably bring them down to rates of growth no lower than other companies in other areas.

Q. Your second area of disagreement was with Mr. Frazier's conclusion that gas companies operating outside the New England-Mid Atlantic region, generally, can absorb a 10-cent increase in their gas rates without a material impact on their favorable competitive position. Please explain the basis for your disagreement.

A. I would first like to look at the Gulf Coast area, which FRC projections to 1980 indicate will account for approximately 31 per cent of the growth in the country's

natural gas use. As shown on Schedule 1 of my exhibit, more than 70 per cent of the sales in that area are for industrial use. If there were some way to bring about Mr. Frazier's assumption, that is, a price increase of five cents to ten cents per Mcf for these sales, I

[2,023]

would be very surprised if the demand and growth in Region 7 were not affected. Furthermore, Mr. Frazier has erred in his analysis of the competitive situation in Region 4 and the western part of Region 2. The residential load growth will be relatively low because of the high saturation in these areas, as shown in Schedule 2, regardless of the residential rate. There could be substantial competition in the industrial and interruptible markets, however, which accounts for approximately 48 per cent of the sales in Region 4, and in excess of 40 per cent in Region 2. Much of this industrial market is more elastic, both for load growth and existing customers, than is the residential market. It is unusual for residential customers to convert from gas because of rate increases, whereas industrial customers are more likely to convert to another fuel after a substantial rate increase. For these reasons, I believe that the companies outside the AGD area will be faced with problems of competition every bit as severe as those faced by the AGD customers.

Q. Your third point of disagreement with Mr. Frazier is with his conclusion that a multiplier effect causes

[2,024]

the impact of a wellhead price increase of one cent to produce a two cent increase at the retail level in New England. Would you please comment on this difference.

A. I am not sure what Mr. Frazier specifically refers to here, but first an increase in wellhead price in no way increases other revenue requirements of the pipelines or distributors. Their return and tax requirements are not increased, for instance, so that a five cent increase for flowing gas at the wellhead will mean a five cent increase at the city gate, and no more. Likewise, under rate making policies long used by the FPC, this same five cent increase will flow through to customers on the Gulf Coast and New England alike. I assume that Mr. Frazier understands this, and that his reference is to the possibility that an increase in wellhead prices will cause a loss of sales in the AGD companies market areas, that this loss of sales will result in rate increases that will result in further loss of sales and so-on. In my opinion, to the extent that this would happen, the areas *outside* the New England-Mid Atlantic area would be more seriously affected.

This is so because of the large proportion of large industrial customers in other areas and the relatively large proportion of inelastic load in the New England-Mid-Atlantic area.

Q. Please comment on Mr. Frazier's conclusions regarding price-demand relationship, as expressed on Transcript pages 1368 and 1369 of his testimony.

A. Mr. Frazier has concluded that price changes substantial enough to affect demand in the area where the bulk of the gas is consumed would amount to penalties to consumers in the order of two and one-half billion dollars per year. This amounts to an increase of 10 cents on each Mcf of flowing gas, or $2.85 per Mcf when these same dollars are applied to the production from new gas only.

Proposed Testimony of Charles A. Larson

In my opinion, price changes of a much smaller magnitude would put the interstate market in a most favorable competitive position with respect to the intrastate market.

Next, even assuming Mr. Frazier's price increases of 10 cents across-the-board, I believe he is exaggerating to suggest that such increases would put the gas distribution

[2,026]

industry in the New England-Mid Atlantic area in serious jeopardy. My experience has been that these companies are very vigorous and very healthy and serve a relatively high proportion of inelastic loads.

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[2,412]

TESTIMONY OF H. D. BORGER

BY MR. COOPER:

* * * *

Are there any changes of fact that have occurred since April 1st as to your present situation during this summer which you would care to now state as the present situation of the company?

* * * *

THE WITNESS: The testimony on that date was that the Consolidated System needed an additional growing supply on November 1, 1970, of 200 million a day, which included 40 million a day which we have been getting this year and which we hope to have continued on November 1st, 1970, from the Tennessee Gas Transmission Company coming from Canada.

[2,413]

Being unable to contract for the 75 million—or for the 200 million a day, the alternative to getting us through the Winter of 1970-71 is to increase our storages and attempt to purchase summer gas that would give us sufficient storages to get us through this coming winter.

The only change or addition to this testimony would be that we have made those arrangements with various people and at the moment, unless the situation changes materially between now and November 1st, our storages should be filled to their designed capacity at November 1st, 1970.

This has been done by buying gas from various distribution companies that are unable to take it in the summer from as far away as Providence Gas Company, New Bedford Gas Company, the Cambridge Gas Company, all in Rhode Island and Massachusetts, from Brooklyn Union Gas Company, from the Long Island Lighting Company, from the Equitable Gas Company in Pittsburgh.

These companies are selling us gas at—usually at a premium rate. In the case of the Long Island Lighting Company, it is being sold at a rate of 51.4 cents, which is the cost to Long Island Lighting of substituting low sulphur oil for the gas that they normally burn under their boilers in the summertime, and they are transferring that to us for storage.

This is also true of Brooklyn Union, who normally sells its gas in the summer to Consolidated Edison to be burned under boilers.

[2,414]

The other four companies are selling it on the basis of being able to maintain 100 percent load factor rate from their suppliers.

These arrangements have been made through the various pipelines serving these companies, which also serve Consolidated.

In addition to this, the Texas Gas contract, which final step takes effect on November 1st, 1970, of the final 50 million a day—this was started, the first deliveries, on November 1st, 1968. Texas Gas has been able to move forward part if not all of this 50 million until April 1st of this year, which enabled us to put additional gas in storage.

We have made arrangements with the Public Service Company of New Jersey for 4 billion feet on a payback basis.

We have arranged—this figure of 55 billion includes the 40 million a day from Tennessee, which is a temporary year-to-year contract in the total amount of 11.6 billion. It includes 2½ billion of our own gas in Louisiana that we have been able to make a transportation contract on a when-and-as-if basis with Transco. It includes also 9 billion from Panhandle, which is excess gas which they may have this summer and which we may or may not get, depending on their ability to deliver it.

In addition to this, the weather pattern has changed rather drastically as of April 1st, and while January, February and March were exceedingly cold months necessitating the curtailment on the Consolidated System on January 21st, at which time

[2,415]

we asked certain industrial customers having stand-by fuel to go to oil or other fuels, at the end of that curtailment, some six or eight days later, we asked those customers continue on oil, and we have picked up the difference between the premium for oil—the difference between the cost of gas and the cost of oil to those customers as a means of replenishing our storages this summer.

The weather changed on April 1st—April, May and June have been warmer than normal. And while you don't ordinarily think of weather at this time of year making much difference in the amount of gas that is used, it can range as high as five or six-billion feet in these months per month. This has occurred, and at the moment if all these things continue and they are not —they are not firm and they are probably subject to cancellation depending on the situation of each of these companies we have been dealing with. We are presently

in an excess position, or will be, of about perhaps as much as 20 billion feet.

On the other hand, in order to guard against this we have made arrangements with the industrial customers that were on stand-by oil to continue that until March 31st of 1971, as a means of getting us through this coming winter. Hopefully, we would go into November 1st with our storages full and hopefully we will have a normal winter which would permit us to get a start on the Winter of '71 and '72. If we have the same type of

[2,416]

winter we had last winter, we presently have no gas for the Summer of 1971.

What other arrangements can be made then are problematical. These arrangements are only for the summer season. I am not sure that they all expire on November 1st, but certainly they expire early in the fall.

Other than that, which only brings down our supply situation to date, the testimony would be the same.

PRESIDING EXAMINER: Thank you.

BY MR. COOPER:

Q. Mr. Borger, do these short-term arrangements which improved your situation for the year 1970—do they in any way alter the long-term needs of the Consolidated System for additional gas supplies?

A. No, they don't. We have curtailed our sales, additional sales. We hope by this to be able to serve our present customers. This in no way creates a supply that we could use for additional loads coming onto the system, regardless of what type it might be.

We have discontinued any large industrial or commercial sales. We are continuing to take any increases

in the domestic and small commercial market. They are, in relation to the total deliveries for the year, quite minor.

Q. Mr. Borger, have there been any changes since—or developments since April 1st in your attempts to buy long-term

[2,417]

supplies of natural gas?

A. Well, we are still trying, but the situation hasn't changed any. In fact, if anything, it has deteriorated.

Q. I show you, Mr. Borger, on page 908 of the transcript the question there "have you been attempting to secure additional supplies of natural gas from Canada?" And your answer stating the situation on April 1st as to your negotiations with Trans-Canada. Have there been any changes with regard to that situation since April 1st?

A. We have an agreement with Trans-Canada that we would receive about 19 million per day beginning in 1972, 38 million a day commencing in 1974, subject to approval by U. S. and Canadian regulatory authorities.

I met last week, a week ago today with the the Trans-Canada people. They had hoped to accelerate this delivery perhaps by as much as a year in each case. They now tell us that this will not be true, and there is some question as to whether or not the Canadian Energy Board will approve this sale, primarily because of the developing market principally in Toronto.

Electricity in Toronto, downtown Toronto is generated I believe with coal, at least certainly adding to their air pollution up there. Six months ago, in January, they looked at this and decided it wasn't economical to switch it to gas. As I understand it, this is a government-run operation. They have now decided that regardless of the economics that they will use

[2,418]

gas in this electric plant. This could add as much as 160 million a day immediately to the Canadian market. And if that is true, it puts in jeopardy certainly this sale to us in 1972 and 1974.

Nothing definite about this yet; this is just the latest information we have.

Q. These are the only changes since April 1st that would—I mean the facts that you have stated are the only changes that you would care to make in the testimony?

A. I believe that's correct, yes.

* * * *

[2,435]

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A. Well, if you are going to give the producer twenty-six cents and find it is not enough, the results would be a continuation of the shortage. The monetary effect would be rather slight. You can raise the price of new gas to twenty-six cents, and if you don't get it it is not going to cost you any money, and even if it does cost you money, the effect on the ultimate consumer is very gradual in that these prices would all be rolled in with the presently existing prices; it would take a good while to really affect the price.

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[2,436]

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I think the principal reason that we are not getting enough gas is that the producers generally have lost all

faith in the regulatory processes of the Federal Power Commission. Until that faith is restored, you are probably not going to get gas regardless of the price.

The present prices are predicated on a test year of 1960 in South Louisiana, and from my point of view, it is perfectly ridiculous to expect people to produce gas at prices based on a ten-year-old test year in such an inflationary period as we have, and coupled with the fact that many of these producers settled in the 61-2 case and then found their prices rolled back from the settlement which had been approved by the Federal Power Comission. And they are presently in a situation where they can't intelligently make an economic forecast as to the results of any exploratory work they might want to do. Until that basic situation is corrected, I think we are always going to have the problem of the producers being reluctant to produce gas for the interstate market.

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[2,439]

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If the twenty-six cent price which I suggested is not sufficient to bring forth exploratory effort and new gas on the part of the producers, there won't be any payments for it. There is no gas to buy. It can't increase the price on the part of the distributors in any degree at all. Now there might be minor amounts of it.

As far as the increase in price in flowing gas, every distributor is getting increases in their own price based on inflationary costs that are happening to him. Is there no reason to think that the producer shouldn't be treated the same way? I don't think so.

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[2,444]

Now, those pipelines, then, gave you no indication that there was going to be any gas shortage. And this was as early as 1968?

A. Very early in '68, that is correct.

Q. Did they on the contrary give you assurances that there would be ample gas to meet your needs?

A. I don't recall it that way, Mr. Morrow, exactly. It came about because of the fact that we had entered into a contract with Texas Gas in building a new connection to that system for a contractual amount of 200 million a day and a transfer of 100 million a day transport gas to the sales contract, the last of which is being delivered now, was supposed to be delivered on November 1st, 1970. And in the intervention in the certificate cases by the other pipelines at that time they gave no indication of a shortage. They did not assure us that they would have gas in 1970 when this contract was up, for instance, for '71 or '72.

They just——

Q. They did assure you that they had plentiful supplies to offer?

A. We certainly got that impression from the way they were intervening complaining about this sale that would take substantial increase in our market away from them for a two or three-year period. Because this is not the normal pattern for Consolidated. In contracting its gas it generally does it on

[2,445]

a year-to-year basis, with about two years' lead time. And this has been traditional through the '60s. But having to build a thirty-million-dollar pipeline, it was neces-

sary to enter into a longer build-up period with Texas Gas. It gave the Consolidated System a fifth pipeline supplier, which at the time we thought would be very beneficial from a supply point of view. It turned out it hasn't—well, as it turned out, it is very fortunate we did make it or we would be probably short another hundred million a day right now than we presently are.

The idea was not to continue buying exclusively from Texas Gas at all. The company we buy from is determined largely by price at the location at which we need the gas.

These companies come into our system at various points. We can at times pay one company more for gas having it delivered at a particular point and we can pay some other company less and transport it ourselves.

Q. Yes, sir.

A. So there is no reason to think in talking to these companies at the time of those interventions that they were short of gas, because they were complaining about the loss of future sales.

Q. Right, sir.

Did your own system itself have any forewarning at that time that there was going to be the gas supply problem which subsequently cropped up?

[2,446]

A. The first warning we really had in the South Louisiana Area came in the negotiations with Texas Gas Transmission for a supply of gas for this proposed pipeline that was proposed in '66 and finally built in '68, about a year late. After the negotiations were completely concluded in the latter part of '66 we had to wait until Texas Gas went out and made sure they could buy the gas. A number of the pipelines, particu-

larly Texas Gas, had been warning of a deterioration in the gas supply for some time. It took a little while for them to convince us.

I think we first started to recognize it in '67 in a minor degree, early in '67, increasing in '67; and certainly we were fully conscious of what was going on not too long into '68 before we felt that the situation was getting very serious from our point of view.

Q. Wasn't it the Fall of 1968 before the Consolidated System became aware that there was a serious temporary shortage?

A. Let's put it this way: It was the Fall of 1968 before we were willing to admit it to ourselves.

Q. Yes, sir. All right. And isn't—let's see. When in the fall? Do you remember?

A. No, you are taxing my memory.

Q. All right, sir.

It is true, though, that Opinion 546 also came out in the Fall of 1968?

[2,447]

A. I think September 26th was the date of 546.

Q. And I suppose you would find no significance in the fact that the news of the gas shortage broken upon the consciousness of the industry just about the same time that the news of 546 broke upon the industry?

A. I really don't think there is any relationship between the two events.

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[2,448]

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A. Well, major production comes in South Louisiana from the major oil companies. They operate for the most

part world-wide. Exploratory dollars in South Louisiana are in competition with all their other opportunities for investment wherever they might be, whether it is in Prudhoe Bay or in Libya, or Algeria, or wherever. And if they are not in a position to use a price for assessing the economic possibilities of exploration in South Louisiana in competition for their

[2,449]

investment dollars in the other parts of the world, South Louisiana is going to suffer, and has.

PRESIDING EXAMINER: Let's take a short recess.

(Whereupon, a morning recess was taken from 11:15 to 11:30 a.m.)

[2,452]

Do I correctly infer from that you would make the interstate rates at least as high as the intrastate rates?

A. I think there you have to be high enough to be competitive with the intrastate rates, yes, I do. It leads you away from a truly cost concept. And unless we do that—I guess the real answer is that we are going to have to find enough gas to satisfy both markets.

Q. So that the regulated price would depend, to some extent, on what the unregulated intrastate price was?

A. That is right. I think the market conditions should determine the price more than any other consideration.

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[2,455]

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A. I think that a 26-cent price in the field is one that the distributors could handle certainly in their do-

mestic and small commercial market without any problems. The one market that is susceptible to—more susceptible to price than any other is the industrial market. It is affected as much by the change in price in oil and other fuels as it is by the price of gas. I assume there might be some changes in that. We might possibly lose some boiler fuel sales, and perhaps in view of the present supply situation this might be appropriate.

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[2,459]

A. Well, I think presently that most gas companies are getting requests for natural gas as a means of pollution abatement simply because the price is low, it is the most economical way for these various companies to solve their pollution problem.

As I said before, there are other ways, mechanical, such as, oh, filters and precipitators and things like that, and an industrial company will sit down and figure the cost of the capital invested to do it one way as opposed to using natural gas and natural gas is the cheapest, so we have a market for it right away. And this has been booming, particularly in the last six or eight months.

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[2,504]

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I would hope that the 26-cent price would be competitive with these intrasate prices. It might mean that both of them would go up, but at that point we might be competitive.

* * * *

A. Because I think interstate market will go up whatever is necessary to get the gas, and it will eventually get to the point where they say this is it,

[2,505]

and I hope that figure is 26 cents.

I don't think that the intrastate is going to stay constant with the interstate going up. They are going to go up right with it. Hopefully they will come together at 26 cents. Now, they may or may not. That is a matter of judgment.

* * * *

Supplemental Direct Testimony of Joseph P. Thomas

[2,636]

FEDERAL POWER COMMISSION

Docket No. AR69-1

AREA RATE PROCEEDING (SOUTHERN LOUISIANA)
(PHASE I)
THE PEOPLES GAS LIGHT AND COKE COMPANY
AND
NORTH SHORE GAS COMPANY
(Of the United Distribution Companies Intervenors)

SUPPLEMENTAL DIRECT TESTIMONY OF JOSEPH P. THOMAS

Q. Are you the same Joseph P. Thomas whose direct testimony appears at Tr. 938 through Tr. 954 hereof?

A. Yes, I am.

Q. Mr. Thomas, has the occurrence of certain events subsequent to the entering of your direct testimony into the record in the instant proceeding on April 1, 1970 necessitated the altering of your testimony given therein?

A. Yes. Subsequent to my testimony which was entered into the record in this proceeding on April 1, 1970, events have transpired which require that I either supplement or completely revise some of the information which I provided at that time. I will attempt to do this by referring to the page and line number of my original testimony.

Tr. 943—Substitute the following for lines 12 through 17:

The City of Chicago recently adopted a more strict

air pollution ordinance. This ordinance provides the following standards for four specific categories or uses:

a. For new space heating installation the per cent of sulphur by weight in fuel will be limited to 1% beginning July 1, 1970;
b. Existing space heating installations will be limited to 2% sulphur by weight from July 1, 1970 to August 31, 1971, 1.25% from September 1, 1971 to August 31, 1972, and 1% thereafter;
c. Industrial power plants and process plants will be limited to 2% sulphur from July 1, 1970 to October 31, 1970, 1.5% from November 1, 1970 to August 31, 1972, and 1% thereafter;
d. Electric power generating plants will be limited to 1.8% from July 1, 1970 to December 31, 1971, and 1% thereafter.

Tr. 944—Insert the following between lines 2 and 3:

As a consequence of said ordinance, the new construction market must immediately turn to a 1% or lower sulphur fuel, such as gas, and the conversion market must obtain such fuel no later than September 1, 1972, the date when low sulphur fuel becomes mandatory in

existing installations.

In the case of new construction, Peoples Gas estimates the market to be 11,000 equivalents, of which approximately 5,000 equivalents are represented by loads with input levels of less than 5,000 CFH. Insofar as the conversion market is concerned, the potential demand for gas for space heating when the ordinance is completely

effectuated is estimated to be at least (a) 242,000 equivalents if gas were substituted for all coal, (b) 342,000 equivalents if gas were substituted for all fuels not conforming to abatement regulation (including coal and high sulphur oil), and (c) 671,000 equivalents if gas were substituted for all fossil fuels other than gas (including coal, high and low sulphur oil).

Tr. 948—Substitute the following for lines 7 through 21:

In addition to these quantities from Natural, it is hoped that the Mahomet Storage Project will provide an additional 1,000,000 Mcf for seasonal storage capacity for Peoples and North Shore for the 1970-71 season.

The massive demand for additional gas generated by the adoption of stricter air pollution ordinances threatens to outrun our ability to supply loads for

[2,639]

the 1970-71 season and thereafter. For this reason, Peoples Gas and North Shore requested authority from the Illinois Commerce Commission on June 22, 1970 to begin controlling the rate at which we attach new business. The plan which we proposed to use attempts to allocate the available supply in a manner most advantageous to combating air pollution. The Illinois Commerce Commission granted temporary authority to implement the plan on June 26, 1970 and began hearings on July 16, 1970.

We now have the authority to delay requests for service for central space heating and any type of industrial space heating or processing or power generation until adequate supplies of gas are available for such service.

[2,639]

Supplemental Direct Testimony of Joseph P. Thomas

Tr. 949—Substitute the following for lines 3 through 6:

In fact, we have recently been notified by Natural, our major pipeline supplier, that it intends to reduce the quantity of gas previously available to us during off-peak months which we use for year-round firm, off-peak and storage use, and on June 25, 1970, Natural filed a revision of its tariffs on file with the Federal Power Commission to permit such reductions immediately. We do not know the full extent of

[2,640]

this curtailment at this time and therefore, are not able to determine the full impact it will have on our ability to fulfill our firm commitments for summer deliveries and to make sufficient injections to storage to be able to fulfill our firm commitments for winter deliveries. This curtailment will undoubtedly affect our deliveries to interruptible customers.

Tr. 949-950—Substitute the following for lines 18 through 25 on Tr. 949 and line 1 on Tr. 950:

It is my opinion that if the air pollution ordinance recently passed in Chicago were to be strictly and promptly enforced, Peoples Gas, including North Shore, would need additionally between 300,000 and 400,000 Mcf per day in the next year or two to handle the potential space heating loads alone. This would not include supply for additional industrial processing and power generation loads. This is the crisis which required that we obtain authority to control the rate of new business attachment.

Tr. 951-952—Substitute the following for line 25, Tr. 951 and lines 1 through 3 on Tr. 952:

A. Yes. As previously indicated, we have already received authority to control the new business which we attach.

[2,641]

Tr. 952—Delete lines 4 through 21.

Tr. 952—Substitute the following for line 24:

A. Yes. Recently Northern Illinois Gas Company, Iowa-Illinois Gas and Electric Company and Illinois Power Company have sought authority from the Illinois Commerce Commission to control certain of the new business which they attach.

Q. Does that complete your supplemental direct testimony?

A. Yes, it does.

[2,642]

* * * *

BY MR. BRACKETT:

Q. Mr. Thomas, did you furnish information to Mr. Sarikas relative to the Peoples Gas Light and Coke Company and North Shore Gas Company which underlies the gas requirements portions relative to those companies of his exhibit?

A. I did.

Q. Referring specifically to the gas requirements on pages 1, 2, 4 of Schedules 1 of Mr. Sarikas' exhibit, which I believe is Exhibit No. 1 in these proceedings, are the figures for gas requirements which you furnished Mr. Sarikas still accurate for Peoples Gas Light and Coke and North Shore?

A. No, they are not.

[2,642]

Supplemental Direct Testimony of Joseph P. Thomas

Q. If you were to redo those figures now would the figures for gas requirements for the years 1971 through 1975 be increased or decreased for those companies?

A. They would be substantially increased.

Q. Why is that?

A. Primarily because as I state in my supplemental testimony, the new city ordinances passed in the City of

[2,643]

Chicago have made it necessary for many customers to burn gas in place of coal and other fuels, and the market there is quite substantial, and they were not anticipated in the original figures prepared.

• • • •

THE WITNESS: The original preparation of the data submitted to the group did not anticipate the ordinance that was passed last April 8. The testimony and exhibits were prepared prior to the passing of that ordinance, which really came as quite a surprise to all of us.

• • • •

Q. Do you know specifically what the new figures would be for the years 1971 to 1975 at this time?

A. No, I do not.

Q. Why is that?

A. We haven't had the time to assess the extent to which the ordinances will be enforced in the City of Chicago, or the extent to which they can be enforced in the City of Chicago.

Q. Are you able to state at this time whether the gas requirements furnished to Mr. Sarikas for those two companies for the years 1975 to 1980 would be increased

[2,644]

or decreased if you were to redo them now?

A. They would be, in the cumulative sense, increased somewhat, but the total figures for the ten years would not shift nearly as much as they would in the first five years. In other words, the market may stay much the same, be a slight increase in the overall market, but the market would be coming on, as we see it, much sooner, because of these new ordinances passed in the City of Chicago.

Q. And this ordinance was passed subsequent to the time you presented your testimony in this proceeding and was entered in the record, is that correct?

A. Yes, sir.

* * * *

[2,684]

* * * *

THE WITNESS: One of the things we constantly watch, of course, is the competitive costs of other fuels and other services and try to evaluate the value of our own service. And it would be my opinion that if new supplies could be obtained for as high as thirty cents it wouldn't be disruptive to our markets.

BY MR. WAKEFIELD:

Q. Are you talking about field prices of thirty cents? Is that what you are referring to?

A. Yes, sir.

Q. Now, assuming that there was an increase in field prices of that magnitude, how much would that raise your average price as you sell retail?

A. It would raise our average price, on an incremental basis—I am gathering say nine cents for trans-

portation and delivery, to bring gas in, roughly say forty cents as opposed to the present 32, 33-cent rate.

• • • •

[2,685]

• • • •

THE WITNESS: I said thirty cents would not be disruptive to our markets. I didn't say that thirty cents was the right price for gas.

PRESIDING EXAMINER: Oh. You are saying up to thirty cents you would have no problem?

THE WITNESS: Yes, sir.

• • • •

Testimony of C. M. Allen

[3,439]

TESTIMONY OF C. M. ALLEN

Hugoton-Anadarko-Texas Gulf Coast. My testimony in the latter point proceedings was incorporated into the *Other Southwest* record.

Q. Did you rely on the same data for your testimony in each of those proceedings?

A. No, as the proceedings have progressed, data have been obtained from an increasing number of companies. The first evidence I presented pertained only to Phillips Petroleum Company and covered 190 exploratory wells on which predictions were made and were subsequently productive. (AR 61-1, Exh. 186) The statistics reported in this proceeding and set out in composite in Exh. 42 (CMA-4), Schedule 1, now cover 22 companies and 6,142 wells.

Q. Have you prepared a Schedule to depict this progression of available statistics?

A. Yes, these are set out at Exhibit 42 (CMA-4), Schedule 4.

Q. As progressively more companies have provided information on their directional search capability, what have the data on predictive accuracy shown?

A. The composite predictive accuracy of the various groups of reporting companies have appeared to fall within a narrow range of 85-87 percent.

Q. What, in your opinion, is the reason for this consistency of predictive accuracy?

A. Since the first experience by Phillips with maintaining records on the directional search, I have been convinced that any producer with an adequate geological staff can conduct a search for gas reservoirs separate from the search for oil reservoirs. Thus, in 1964, I testified:

"Any producer with an adequate geological staff and data can

* * * *

[3,512]

TESTIMONY OF RADFORD L. SCHANTZ

Have you investigated far enough into this to know what was the basis of that downward extension and revision figure?

A. You are speaking of the year 1968?

Q. Yes.

A. I have not gone beyond the published data by the American Gas Association.

Q. I see.

Are you familiar enough with the industry to know how extensions and revisions are arrived at?

A. I am generally familiar with the definitions used by the American Gas Association Reserves Committee.

Q. All right. What do you mean by the word "extensions," then, as you use it in Schedule 7?

A. Extensions would represent adjustments, typically upward, in the original new discoveries as a result of drilling in subsequent years.

Q. You say typically upward.

A. Yes, sir.

Q. Would there ever be an occasion when extensions would go downward?

A. I don't believe so. I believe that would come under revisions.

Q. Yes.

Then we are agreed that extensions come only from further developmental drilling?

[3,513]

A. Which extends the field, to use the phrase, yes, that is correct.

Q. All right.

Now, what are revisions, as you use this word in Schedule No. 7?

A. Revisions, as I understand the AGA Reserve definition, represents adjustments, either up or down, in previously reported proved reserves as a result of further drilling and production.

Q. Who makes the revisions? What kind or class of person makes the revisions?

A. The American Gas Association Reserves Committee.

Q. Well, are they not made, though, on the basis of reports from geologists?

MR. NORRIS: He has stated that he didn't go behind the AGA figures, Your Honor. The figures speak for themselves.

PRESIDING EXAMINER: Well, if he can't answer the question, all he has to do is say no.

THE WITNESS: Beyond the Reserves Committee, I do not know, Mr. Morrow.

BY MR. MORROW:

Q. So you do not know how the AGA Reserves Committee arrives at its figures for revisions in the course of any particular year?

A. Mr. Morrow, I have read rather casually Mr. Jacobs' evidence as submitted by the Pipeline Group in this proceeding,

* * * *

[3,518]

that statement.

PRESIDING EXAMINER: Well, in my opinion he has answered the question. Ask your next question.

MR. MORROW: All right.

BY MR. MORROW:

Q. Your figure for extensions and revisions, whatever it may be, includes the net of both extensions and revisions; is that correct?

A. That is correct.

Q. And therefore, since it is a minus figure and the extensions are always a postive figure, it must follow that the total revisions for 1968 were greater than a minus—were a greater negative figure than the 642. Is that right?

A. For associated dissolved gas, yes, sir.

Q. Yes.

Do you know from the AGA report what the revisions figure was for 1968?

MR. NORRIS: Do you have a reference in the report you would like to direct the witness to, Mr. Morrow?

MR. MORROW: No. I am asking him.

THE WITNESS: Mr. Morrow, I brought the 1969 document with me thinking that would be more appropriate, and not the 1968 document, but if I had the 1968 document with me I could read the figure off that you are asking about. I do not have it with me, however.

[3,519]

MR. MORROW: All right.

BY MR. MORROW:

Q. Have you read that figure in preparing for this—in preparing this Schedule 7?

A. Have I read that figure?

Q. Yes.

A. You mean——

Q. The 1968 AGA figure for revisions.

A. I am certain that I was aware of that figure when I prepared Schedule 7.

Q. If I gave you the figure 2.4 trillion cubic feet, would that refresh your memory?

MR. NORRIS: Your Honor, counsel seems to have the report before him. If he would like to show it to him——

MR. MORROW: I do not have the report before me.

PRESIDING EXAMINER: Has anybody got the report?

MR. MATTINGLY: Your Honor, I believe those figures are in evidence, but I don't have it with me.

MR. NORRIS: They are already in evidence through Mr. Lindvall's testimony.

MR. MATTINGLY: Yes, they are in Mr. Lindvall's exhibit.

MR. MORROW: Mr. Examiner, I beg to differ. They are not in evidence in Mr. Lindvall's testimony, I don't believe.

MR. NORRIS: Or his exhibit, rather.

MR. MORROW: Or his exhibit. If you show them to me I will

[3,520]

back up, but I have not found them there.

PRESIDING EXAMINER: Did you say you had a report there, the gentleman sitting there?

MR. BASS: This is a '69 report, but the '68 figures are in here.

THE WITNESS: Mr. Examiner, I now find that this data seems to be available in the '69 report, and I am prepared to now answer the question to Mr. Morrow, if he would like to rephrase the question.

PRESIDING EXAMINER: All right.

[3,520]

Testimony of Radford L. Schantz

BY MR. MORROW:

Q. I just want to know what the revisions for 1968 were.

A. For associated dissolved gas?

Q. Yes.

A. This includes Alaska. It amounted to 1,822,482,000,000 cubic feet.

Q. This was the entire figure for associated and dissolved gas?

PRESIDING EXAMINER: You know, you two are playing games with each other. That is the question he asked you a moment ago, and you said yes. Now you are asking him the same question.

MR. MORROW: All right, sir. We will move on.

THE WITNESS: The answer is yes, Mr. Morrow.

BY MR. MORROW:

Q. Can you tell me whether or not there was a negative

[3,521]

revision with respect to oil reserves for that year?

MR. NORRIS: It would certainly be helpful if counsel could furnish page references in the report when he is asking questions of this nature based on the report, Your Honor.

PRESIDING EXAMINER: Do you have a reference to some document?

MR. MORROW: No, Your Honor, I do not.

THE WITNESS: Mr. Morrow, in 1968, for the total United States, revisions in proved crude oil reserves were upward—were a positive number.

MR. MORROW: Thank you.

BY MR. MORROW:

Q. Now, you said a few minutes ago that you have the figures for 1969 on extensions and revisions from the AGA.

A. Yes, I do.

Q. Would you give us those figures?

A. Well, I read those on the record at the outset of the hearing. Do you mean beyond what I read on the record?

For Schedule 7, this was the first duty I undertook this morning, to bring forward to 1969 that data.

Q. All right. I seem to have missed that.

MR. MATTINGLY: I did too.

MR. NORRIS: You didn't correct Schedule 7, Mr. Schantz.

THE WITNESS: Pardon me?

MR. NORRIS: You corrected Schedule 4. I did not indicate that you had corrected Schedule 7.

[3,524]

Mr. Schantz, of the AGA Reserve Report of May, 1970, for the Year 1969. And I would ask you to look at that page and confirm that the extensions and revisions for nonassociated gas supplies for 1969 which you gave us, that figure is a net of a plus extension figure of 4,788,627 and a negative revisions figure of 1,460,196. Is that correct?

A. Yes, it is.

Q. Thank you.

Mr. Schantz, do you know of any other occasion over the years when there have been two years in a row of substantial negative revisions reported by the AGA? I mean overall.

A. I haven't studied that matter, Mr. Morrow. I would have to go back and examine the——

Q. All right, sir.

A. ——documents to answer your question.

Q. Yes, sir.

Do these negative revisions for the years 1968 and 1969 affect the R/P ratios for those years?

A. Yes, they certainly do.

Q. Now, if the extensions and revisions for those years had gone forward at the normal rate that they had been experiencing for the previous three, four or five years, then is it true that there would have been very little decline in the R/P ratio in '68 and '69?

A. There would have been a decline. In fact, I think it

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[3,801]

* * * *

KENNETH C. VAUGHAN

was called as a witness, and, after having been first duly sworn, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. REBMAN:

Q. Please state your name and address for the record.

A. My name is Kenneth C. Vaughan. I reside at 1512 Kensington Road in San Marino, California.

Q. Mr. Vaughan, are you the same Kenneth C. Vaughan whose prepared direct testimony appears in Volume 12 of these proceedings at pages 1749 through 1766?

A. I am.

* * * *

[3,803]

* * * *

A. Yes, sir, we operate in the full State of Louisiana, both onshore, the offshore state portion and in the Federal Domain offshore Louisiana.

Our operations are confined to oil and gas operations. We do not have any marketing.

Q. Would you say, if you can, whether or not you are looking primarily for oil or for gas in the Southern Louisiana Area?

A. We are looking for both.

Q. Has Union cut back its exploration or leasing or drilling activity in Southern Louisiana in the last several years?

A. Well, yes. I think on a long-term consideration we have cut it back. However, the offshore sales in the—well, excuse me. The offshore sale did not take place in Louisiana. I was going to refer to Texas. Yes, we have reduced our operations in Louisiana.

Q. Do I understand correctly that you have done so primarily for lack of prospects on which to explore?

A. Not primarily for that alone. That certainly is one factor, but admittedly gas and oil are becoming more difficult to find. And certainly the primary purpose is the economic climate in which we are working, is the most important factor.

[3,804]

Q. When you use the term economic climate, could you be more specific as to the factors that enter into your analysis of the overall economic climate and how it affects your decisions?

A. Well, in the case of exploration and development of natural gas, natural gas condensate and natural gas liquids, the price of natural gas during the last several years has certainly be a deterrent.

Q. Would it be possible for you to provide an indication, an estimate or a specific indication of the price which in your view would be necessary in order to induce Union to accelerate its activities in the Southern Louisiana Area, particularly with regard to an increased effort directed toward gas?

A. No, sir. Union is currently drilling the more attractive prospects, even at today's prices. And certainly with each new higher level of prices we would be encouraged to drill additional wells that would previously have been considered marginal.

* * * *

[3,812]

sort of an analysis.

Q. Those are costs which are directly incurred in the project itself?

A. Yes, sir.

Q. My question is out of what income or what expected income, cash flow, do you defray the cost of dry holes that may be incurred on other unsuccessful projects?

A. We make no attempt. The fact that we have been unsuccessful in the past has no bearing on our analysis of the individual project then under analysis. If it on its own feet appears to be a viable project, then we are not concerned with what has happened heretofore.

Q. Moving on to 1756, line twenty-four, where you speak of the concept of alternative investment opportunities.

Would you describe in somewhat more detail the principle types of alternative investments against which gas prospects must compete for Union's available capital?

A. Well, here again there is a whole myriad of opportunities for investment. I think it ranges all the way from investments that essentially have no rate of return: a necessary replacement; investment to meet some new environmental restrictions, pollution controls. It would include investments—with respect to natural gas it would include investments in oil; it would include investments in natural gas processing plants. Since we are an integrated company it also includes investments

[3,813]

in refining and marketing and transportation and so forth.

Q. Insofar as Union is concerned would it be an accurate statement to say that the alternative investment

opportunities are primarily centered in the petroleum—various aspects or phases of the petroleum industry?

A. No, sir, we have some diversification. We have interests in copper mines, we have a mineral exploration company that is in the hard rock mineral exploration. We have petrochemicals that sometimes are related to products but not in every instance. And we have other ventures in graphite, so forth, that would also be included as alternative opportunities.

Q. At the top of page 1757 you speak of the one alternative being municipal bonds which are virtually riskless.

Does gas have to compete with investments in municipal bonds at Union?

A. No, I think we use this merely to indicate the very large scope to the scale of possible investments. And I think we indicated this might be considered as far as we are concerned on the lower end of the scale. If we had a lot of surplus capital for any particular period of time, which I assure you we do not, you could look at municipal bonds as a possible investment.

Q. Moving down to line twenty-two, you use the term evaluation of those which meet or exceed guideline requirements. Would you please elaborate on what you mean by guideline requirements?

[3,821]

Q. All of this information which you describe on 1758, is that all before you physically in a—for your personal review?

A. Not in every instance. In many cases if we are working in known areas, a lot of these questions we are alerady aware of, I mean. And when you approve a well in Terrebonne Parrish in Louisiana and you then have

the opportunity to approve another one, you certainly can take some short-cuts with respect to some of the items shown here.

Q. All right. How does your company evaluate acreage which you may be considering for leasing in unexplored areas or areas where relatively little drilling has taken place?

A. Well, again geologically we have—depending again upon the character of the area, we have a great many tools and devices besides so-called surface geology to give us an indication of the attractiveness or the desirability of the area. And this preliminary work then is supplemented by various geophysical means: Magnetometers, gravity meters, seismic, in order to further give us guidance and information as to the prospectiveness of the area.

Q. Turning now to 1760 and 61, page twelve of your prepared testimony at lines 5, 6, and 7. Would you describe to the degree you can the nature and the extent of exploration and development projects in Union's portfolio?

A. Would you repeat that question, please.

[3,822]

* * * *

THE WITNESS: Well, there are many projects in the portfolio that quite frankly, candidly, I don't know about. I cannot maintain a complete awareness in each of our many district offices. However, in reviewing—in our rounds, in our budget rounds we review all those projects, all those prospects that in the opinion of the district and the region they feel are in presentable and in a drillable order. I am aware of all those in detail. And many of those, of course, may be deferred to another

year, may be ultimately rejected. I am familiar with those projects.

BY MR. MATTINGLY:

Q. Would it be correct to say that the oil and gas division of Union has at the present time an extensive number of projects which could be undertaken in its portfolio, extensive as opposed to relatively few?

A. I can never recall a time when we have been able to—when we have been able to get approval for our entire suite of prospects.

I would say that we have a sizeable number of prospects in our portfolio.

Now, I must admit quickly that many of those are in various stages of analysis and interpretation, but we have a number of prospects.

[3,823]

Q. Does that hold true in the Southern Louisiana Area?

A. Yes, sir.

Q. Moving down to lines twenty-three through twenty-five, at the present time could you indicate to us what are as of right now the most attractive types of investments available to Union? Or to the oil and gas division?

A. Well, I would say—and again this has to be based on management's judgment as to what constitutes the most attractive prospect. The very fact that we are currently drilling oil wells, and as a matter of fact in some instances gas wells too, suggests that in our opinion these are attractive prospects. And to try to rate them, however, with others is a little perhaps difficult, and this, of course, is the reason that we use as one measure this so-called DCF—discounted cash flow rate of return analysis.

Certainly our oil and gas exploration historically and currently are investments we feel to be attractive.

Q. Mr. Vaughan, are you selling gas at the present time and attempting to market gas where you discover it in the intrastate market?

A. Yes. Not at the present time. I don't believe that we have any negotiations currently active, but one of our most recent discoveries, made jointly with others, in West Texas was sold to the intrastate market.

* * * *

[3,829]

qualified witness to get into the complex determination of what happens to a barrel of oil after we put it through our transportation facility. Determining just what happens to that barrel of oil all through the refining process and eventually into the market is beyond my ability to answer intelligently.

Q. Very well.

Mr. Vaughan, I will tell you the reason I asked you that question. I simply am trying to ascertain whether or not if the price went up for natural gas and drilling for gas became more attractive, whether or not Union Oil Company couldn't apply some oil revenues to that search.

A. We do at this time. In most cases—or in many cases we don't know whether we are looking for oil or gas.

Q. That was my next question.

I would ask you whether if the price were raised substantially for natural gas in Southern Louisiana and gas properties thus became more attractive, could Union direct its search for gas, and if so, to what extent. In

other words, what I am asking is what, in your opinion, is Union's directional capability?

A. Well, we maintain, of necessity, an awareness with respect to geological areas as to whether the probability of finding oil or whether the probabilities of finding oil is better or worse than finding gas, and conversely.

We do not maintain any formal records in this regard, but

* * * *

[3,831]

Q. And if that activity is accelerated, is it your view, is it your testimony that that can be—within limitations as determined by geography, geology, varying between companies within any geological province, but as a general matter, the search could be directed by Union, by you, by the Oil and Gas Division, generally towards gas as opposed to generally towards oil. Would that be a fair statement?

A. Well, I don't know necessarily that it would. I think it would depend on what particular area of Louisiana you were looking at.

Any increase in the price of natural gas, hopefully substantial, would certainly improve the natural gas prospect in comparison with the spectrum of all the other alternatives we have, and would certainly—and I think logically lead to additional drilling for gas, for gas condensate, for natural gas liquids and for oil, all the products.

I would hope that we don't get into a serious administrative problem of trying to determine whether initially we are going to be drilling for oil or gas or what not, but it would get into exploration. And I think you must remember that when oil is found, gas is also found.

Q. When these drilling projects come to you for approval and you consider all the factors which are set forth on 1758, for example, do you generally know whether you are talking about potentially drilling for a gas reservoir over an oil reservoir,

[3,832]

or sometimes you know and sometimes you don't? How would that be?

A. Well, yes. Again within the framework I described awhile ago, certainly we maintain an awareness. If, for instance, we were drilling a well out in the Hugoton-Anadarko, I would say for all intents and purposes we were looking for gas, although we have found oil there. If, on the other hand, we were drilling, let's say over in the eastern part of Louisiana, although we found a great deal of gas, I would say the probability would be toward oil.

Here again, though, this is not necessarily descriptive, because sometimes depth also becomes a consideration. So in looking at the individual project, if there is a question in our mind, we test it. We check the sensitivity of our evaluation by using oil or by using gas and condensate or natural gas liquids or combinations thereof.

Again, as a final test to determine the attractiveness of a prospect.

* * * *

[3,834]

* * * *

I think it is recognized in the industry that the offshore province is certainly an attractive prospecting ground, particularly, perhaps, for major type discoveries.

Certainly, the State of Alaska—still remaining domestically, the State of Alaska is a new horizon and one that I think has a tremendous future responsibility.

[3,835]

MR. MORROW: Excuse me. By offshore province you refer to South Louisiana, not the Atlantic or Pacific?

THE WITNESS: No, sir, I am including the offshore province totally.

At the same time I would in no way downgrade the potential supply, supply available—potential reserves that I feel are in existence in many of the on-shore areas. Even with the best of our—of the geological tools that we use today, they certainly fall far short of telling us specifically where the gas and the oil is. We can get indications, we can find that in—in some areas we find that many of the factors make it attractive for exploration, but we don't have a tool that will find one or the other. And because of the fact that in the past we have used these tools to delineate or outline one of the more attractive structures, this does not mean that there aren't some very subtle structures, some stratographic traps of the East Texas Field type that are in existence in the domestic US. They are difficult to find. They are more difficult, certainly within the scope of our present tools they are more difficult to find, but I think they are in existence and I think in time they will be found. The probabilities, however, are not as good as looking at a prospect where we feel there is no question about the structure, no question about the stratigraphy, no question about the fact that in the near area there may be hydrocarbons.

I think the whole United States is still a happy hunting

ground as far as future reserves is concerned.

PRESIDING EXAMINER: Suppose the price were increased to the point where exploration and development became more readily attractive to the extent you would like to see it. Would we still have to depend on gas from foreign sources within the next 15 or 20 years, do you think?

THE WITNESS: Yes, sir, I firmly believe, as in the case of crude oil, that the rather almost insatiable demand of the American public for energy in all forms, and specifically in this hearing for natural gas, would make it, I think, impossible for just natural gas industry alone to furnish this supply.

I think we are going to have to rely on alternative supply sources, and I believe that other sources of energy —most economists who have taken a look, for instance, at nuclear energy I think are in pretty much agreement that toward the end of this century, that nuclear energy could be furnishing as much as 25 percent of the total energy requirements of the country.

Now, to the extent that synthetic sources might be available, if you put a price high enough, let's say, to the point of justifying gasification of coal, gasification— not only the mining but retorting recovery of shale oil and the conversion of that to natural gas, perhaps even the exploitation of the tar sand, all of these things, on that basis I would say, yes, there would be a chance for some period of time we could furnish our requirements. But all of these things are certainly

[3,837]

not I think within economic reach and I think it would not be in the public interest to suggest that we should fill

the natural gas supply from, let's say, shale oil. I think the costs would be unreasonable in comparison to alternatives at least at this time.

PRESIDING EXAMINER: Of course, an improvement in technology could——

THE WITNESS: Oh, indeed.

PRESIDING EXAMINER: ——could decrease our dependence on foreign sources, couldn't it?

THE WITNESS: Yes, indeed. And, as a matter of fact, improvements in technology actually increase reserves without drilling in the sense that if we can develop better ways and means of getting more hydrocarbons out of the ground even in an existing reservoir, to the extent of that technology we have increased the reserves.

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[3,838]

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BY MR. MATTINGLY:

Q. Mr. Vaughan, do you believe that the offshore Texas area will eventually become a prolific gas-producing area?

A. Well, how do you define the word "prolific"?

Q. Like Southern Louisiana offshore.

A. Well, to date there are no indications that offshore Texas would be as prolific, and I speak with some authority having made some serious bids on offshore tracts lately in Texas and having failed to find what we considered a commercial deposit.

On the other hand, the density of wells drilled off Texas

[3,839]

is far less than that drilled offshore Louisiana. And I would be the first to admit that a great deal more drilling will be needed, a great deal more geological work will be needed before the answer to that question is finally attained.

I do feel that there will be—I don't know whether the word "prolific" would fit it, certainly not in the sense of a Louisiana comparison, but I do feel that there will be quite a bit of gas produced offshore Texas.

Q. But the results to date have not been encouraging, I take it?

A. The results to date would hardly afford a comparison with South Louisiana.

Q. Mr. Vaughan, do you believe that it is possible that substantial price increases for gas produced in the Federal domain area, offshore Southern Louisiana, would lead to substantially increased lease bonuses, thereby siphoning off funds which would otherwise be available for exploration—available, let us say, for drilling?

A. Well, in the evaluation of any lease I must frankly admit that as its attractiveness improves, so also goes the size of the bid.

However, this gets back again to the individual interpretation that a company places on a block. Sometimes very large bids with no competition and sometimes—and many times those so-called attractive and desirable leases turn out to be dry.

[3,840]

And conversely, sometimes the lower priced leases which fail to get the size of the bonus or the competition turn out to be the better ones.

Here again, we have to work within the limit of the tools available. But quite frankly, if you add to the attractiveness of the lease, I think I would have to say that there is a possibility that the bids would so reflect that attractiveness.

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[3,843]

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Q. All right.

Now, during the break we were discussing very briefly

[3,844]

a statement that you had made in response to Mr. Mattingly's question to the effect that it was not a fair statement that the search could be directed by Union generally towards gas rather than oil. Do you recall our conversation?

A. Yes, sir, I do.

Q. And I believe you said you would like to elaborate or correct that?

A. Yes. I will admit that I don't believe I was too articulate in respect to answering that question, because previously in response to another question I had indicated that any increase in the price of gas would certainly improve the attractiveness of any gas project in relation to the spectrum of other alternatives, including oil exploration. But generally speaking, yes, we do maintain an awareness, a directional awareness, and any prospect, any project that comes along, in analyzing it we certainly analyze it on the basis of the product that we expect to —that we anticipate we will find.

Q. In South Louisiana do you have any idea about what percentage of your wells are joint wells, gas and oil?

A. Well, with respect to gas and liquids, including condensate, they are all joint wells. I don't believe we have any so-called dry gas wells only.

Q. All right.

Then in the event that there was a substantial increase in the price of oil at the wellhead, would this have an effect upon your total oil and gas operations in South Louisiana?

[3,845]

A. Yes. A substantial increase in the price of oil would have a parallel effect to a substantial increase in the price of gas with respect to additional exploration. I think I mentioned that we are currently exploring for gas even at today's prices; we are currently exploring for oil. Certainly any increase in these values would make those prospects that were previously considered marginal more attractive.

Q. And an increase in the price of oil would then probably result in increased findings of gas in South Louisiana, wouldn't it?

A. I think I stated earlier to a previous question that gas is almost—in fact, is always associated with oil, and there would be an increase in gas with increased oil exploration.

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[3,846]

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Q. So that even if we got an increase in the price of gas, if it were accompanied by a decrease in the price of oil, those two would tend to be offsetting in their effect

upon the drilling operations of the producing industry in South Louisiana?

A. I think the general reply to that question would be yes. However, I think that if the gas exploration and the price of natural gas would justify it there would still be drilling done for gas and the higher price for gas would be directed to search and exploration. There would still be an acceleration.

But a reduction of revenue from oil, from condensate, from natural gas liquids, from natural gas, would certainly make capital availability a very serious problem and undoubtedly would reduce the amount of exploratory effort.

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[3,848]

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THE WITNESS: Well, I don't necessarily agree with this. Certainly in exploration nowadays, both in South Louisiana and in other areas, we are looking at greater and greater depths. And I think in looking at greater depths we are essentially directing our explorations essentially toward natural gas. And I don't believe that in light of those current conditions we could say that because currently the revenues derived from oil represent 80 percent that you would have a direct and equatable reduction in the exploration for gas. I don't believe this would necessarily—you could necessarily directly equate those things.

[3,850]

Q. Now, if the demand for gas is insatiable, then how does it come into balance with supply?

A. Well, I think this was in reply to a question from the Examiner, and I said almost insatiable, and I cer-

tainly would stand corrected with respect to the definition of the word "insatiable". There is a very heavy demand. I would not describe it, if you want to become technical, as an insatiable demand. I think I used in my prepared testimony an expression of narrow the gap. And I used that because the past prices for fuel gas at abnormally low levels have created two conditions that have seriously contributed to today's shortage, and the first of those, of course, is this very heavy demand, this overstimulated demand for natural gas because of these low prices, and the concurrent, or the parallel depressing effect that those low prices have had upon the development of alternative fuels.

Now, in my opinion the total supply of gas, the total potential supply of gas is large, although admittedly looking for it and developing it is increasing with time, the difficulties.

But again repeating, in my opinion the only way that the supply deficiency can be corrected—first of all, let me back up and say that I don't know of any way that it can be corrected immediately, and it can only be corrected in the future through a combination of prices for natural gas in the competitive free market and the resulting reduction in demand.

[3,851]

Q. Then in effect I believe what you are saying is that——

A. May I stand corrected. It is the growth of demand, not in demand. But a reduction in the growth of demand.

Q. All right. What you are saying is that as long as the price of gas is regulated at a level lower than the free market price you are going to have a greater demand than supply, the two are not going to be in balance?

A. That is correct.

Q. And, of course, that has been the case ever since natural gas has been regulated, hasn't it?

A. No, sir, I think there were periods during the regulation where the two came into reasonable balance. I say that from personal experience of selling gas on the other end. I think at that time we were knocking on the doors of some of the buyers rather than the reverse order.

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[3,853]

THE WITNESS: Essentially not.

PRESIDING EXAMINER: They are not permitted to use it, are they?

MR. MORROW: He said with Virginia Electric Power.

PRESIDING EXAMINER: I know, but I asked did the same situation exist in California. It is not competitive there because you are not allowed to use coal, are you?

THE WITNESS: Well, but we do have electricity and we do have fuel oil.

BY MR. MORROW:

Q. Did you lose the sale to Virginia Electric Power?

A. The negotiations broke down. Yes, we did lose the sale.

Q. Was that because coal was cheaper than gas?

A. That was one of the factors, yes, sir.

Q. All right, sir.

Now, I will get to my cross-examination.

PRESIDING EXAMINER: Before you do that, there is something I find rather confusing. If you dig a well you don't know whether you are going to hit oil or gas or both, do you?

THE WITNESS: Well, I tried to clear up the answer I had given previously, that, yes, based on our experience in given areas, we have an awareness of directionality. We know pretty well whether we are looking for gas in one area or for oil in another. Now, if we were in a new area, certainly your estimate

[3,854]

is correct. If we are in a new area and we are not familiar with adjacent—and there is no adjacent wells have been drilled——

PRESIDING EXAMINER: How about in the offshore area of southern Louisiana?

THE WITNESS: Well, in the offshore area of southern Louisiana, here I would say that, no, we can't separate gas only from the liquids because in almost every instance in South Louisiana we are looking for both. However,——

PRESIDING EXAMINER: If you had your druthers, you would rather hit oil than gas, wouldn't you?

THE WITNESS: Well, both are attractive under particular circumstances.

If you had a given size reservoir, if the reservoir had a certain pore space that would contain either gas or oil we would prefer the oil.

PRESIDING EXAMINER: The thrust of my question is why would the exploration and development of an oil well, where you hit gas, be affected by an increase in the price of gas? You are really looking for oil, aren't you, and would the exploration and development of an oil well be affected by the price of gas?

THE WITNESS: No, sir. When you use the word oil, or gas—oil only or gas only, we have—although we, the Union Company, do not maintain formal records as to

what well is looking for gas or oil, each project we look at individually, each project that we evaluate we look at on the basis of the

[3,855]

probability of finding oil or finding gas.

Now, when we speak of a gas well, we are normally also speaking of a gas condensate well. And my reply to you initially about South Louisiana is that, well, yes, if you include condensate as a liquid, then the directionality means very little. You are looking for both.

However, we could still differentiate in areas with some degree of accuracy as to whether that area is gas and gas condensate prone or whether it is possibly oil. We can make that differentiation.

PRESIDING EXAMINER: Well, I don't know whether I am expressing this very clearly. But you do keep exploring and developing for oil.

THE WITNESS: Yes, sir.

PRESIDING EXAMINER: Now, is that exploration and development which is primarily for oil affected by the price of natural gas? You are going to be looking for the oil in any case, aren't you?

THE WITNESS: Not in any case. And I guess I am not making myself very clear.

There are certain areas in which we drill where the primary product that we obtain is gas.

PRESIDING EXAMINER: Well, is it then your testimony that if the price of gas were raised you would pay more attention to the areas where you would expect to find gas?

[3,856]

THE WITNESS: Yes, sir. It would improve the attractiveness of that prospect in comparison with the

spectrum of all other projects, including oil, it would make it more attractive.

PRESIDING EXAMINER: When you do hit a well which has oil and gas you can't leave the gas and just take out the oil, can you?

THE WITNESS: No, sir.

PRESIDING EXAMINER: You have got to take them both out.

THE WITNESS: That is correct.

[3,869]

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What I am trying to find out is what is the basic thing that motivates the company in choosing between whether to pursue a prospect or a project in South Louisiana or whether to pursue it somewhere else. It is profitability in terms of your overall return on your DCF approach, isn't it?

A. Yes, sir, with respect to the DCF.

Q. Okay. And so when you look over your suite, is that the word?—Your suite of possible investments within the oil and gas division and you find another location outside of South Louisiana with comparable risk and a higher prospect of return, then you would go to that other prospect?

A. By your definition, if I understand comparable risk——

Q. Well, I want to use your definition of comparable risk, not mine.

A. Are you perhaps even getting into the international operations?

Q. Yes.

[3,869]

Testimony of Kenneth C. Vaughan

A. These are difficult to compare, but in looking at risk on an international operation, in addition to all of the geological risks that I have described herein, all of the things

[3,870]

we look at in determining whether or not it has geological merit, and in looking at the economic evaluation that we then place on it, and of course looking at risk—with respect to foreign operations, on a comparable basis we would demand a much higher rate of return. And of course the reason here is that you have a new kind of risk in the political sense. And I suppose if that factor in management judgment is properly evaluated, yes, some projects will be drilled in the international arena rather than one of those in South Louisiana or Alaska.

Q. All right. I am trying to get as clearly as I can the list of the factors which go into your choice of one project within the oil and gas division as against another. Do you think we have pretty well covered them, or are there other factors which go into making up that choice that haven't been mentioned so far?

A. I believe that the essential factors that I have presented in my prepared statement pretty well cover the situation.

Q. All right. Then I take it that the company gives no consideration in making these determinations of where to drill to its customers' needs for gas, or the needs of the country as a whole?

A. Well, we certainly have an obligation to the community in which we live, the county, the state and Federal Government, along many lines. And I mentioned those this morning in reply

[3,871]

to a question about the social, charitable and so forth. But when it comes to a business decision, after we have spent the money necessary to meet those obligations, after we have eliminated all of those things, then we have an obligation to our stockholders to invest their money in the best possible manner. And by that I mean in the hope that we could obtain the best return.

Q. All right. But the social obligations that you spoke about earlier, you spoke in terms of contributing to a charity or a college and in terms of working with minorities and not in terms of any obligation to your pipeline customers or to their distributor customers.

A. Well, we do not feel that we have an obligation, certainly written or implied, to a pipeline customer to spend money on uneconomical projects.

Q. Suppose they are not uneconomical; suppose there is a prospect in your DCF analysis of a profit but it is not as high as a profit that you could make elsewhere on a comparable risk project.

A. Well, to date we have had no difficulty in finding the capital for exploration and production in the oil and gas division. We have had no difficulty in arranging for capital to ultimately drill that prospect, if it is truly a viable project and if it is truly a project which in our estimation is profitable.

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[3,875]

CROSS-EXAMINATION (resumed)

BY MR. MORROW:

Q. I believe we were on page 1572 of your testimony, Mr. Vaughan, and we were talking about the company's total pool of funds.

[3,875]

Testimony of Kenneth C. Vaughan

I believe we have established that of the oil and gas division funds, approximately twenty percent of that comes from gas and the rest comes from liquids.

Could you tell me about what percentage the oil and gas division represents of the total company's pool of funds?

A. Approximately 24—25 percent.

Q. So that——

PRESIDING EXAMINER: Isn't that rather high, Mr.——

THE WITNESS: Are you talking about percentage of total revenues?

BY MR. MORROW:

Q. Yes.

PRESIDING EXAMINER: Is that unusually high with Union? Because I have heard testimony in some of the other cases I have been in where gas revenues total about maybe three percent of a producers——

THE WITNESS: I misunderstood your question. Was this gas only?

PRESIDING EXAMINER: ——total revenue.

MR. MORROW: No, the way he put it, Mr. Examiner, it would

[3,876]

indicate that gas revenues are twenty percent of twenty-four percent, which would make it about five percent of the company's total revenues, wouldn't it?

THE WITNESS: That is correct.

PRESIDING EXAMINER: What does the twenty-four percent represent?

MR. MORROW: The oil and gas division is twenty-four percent of the entire company, and the gas revenues are twenty percent of the oil and gas division.

PRESIDING EXAMINER: I see.

MR. MORROW: Or about five percent of the whole company just in round numbers.

PRESIDING EXAMINER: That clears it up.

BY MR. MORROW:

Q. Is that right, sir?

A. That is correct.

MR. HOLTZINGER: Could I ask just one clarifying question. When you say oil and gas division revenues, is that wellhead revenues?

THE WITNESS: Yes, sir.

MR. HOLTZINGER: All right.

THE WITNESS: Wellhead and natural gasoline plants or extraction plants.

PRESIDING EXAMINER: All right.

BY MR. MORROW:

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[3,879]

Q. Is this decline on the part of Union Oil in its capital investment outlays a result of the inability of the company to make any larger capital investments, or is it simply a policy decision to curtail?

A. Well, the availability of capital, of course, or the amount of money, capital investment to be made in any one year is a policy decision. But I would say that any reduction in exploratory expenditures would be more the result of a lack of—or would be more a result of fewer viable exploratory prospects under prevailing conditions.

Q. Then you are telling me that if Union had wanted to, it could have spent more capital investment in exploration and development. I mean the funds were available if it wanted to?

A. Yes, sir.

Q. At page 1755, on line seventeen, you state that in the United States you currently expect that only one well in fifty will be commercially productive. And you are speaking in terms of exploratory ventures. Are you talking about exploratory wells or all wells?

A. I am talking about exploratory wells.

Q. Has this one-in-fifty figure been representative of the company's experience in South Louisiana onshore and offshore?

A. No, sir.

Q. Has your experience been better or worse than that?

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[3,886]

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A. Well, perhaps that needs some clarification. We do not take into consideration the specific dry-hole costs. However, dry hole costs in the area involved is an important factor in our determination of the overall risk involved, which is a factor.

[3,891]

Now, let's turn to 1763, if you will.

Beginning at line 9 your sentence is that raising the price on flowing gas will be the quickest and most effective way to correct this situation—the shortage I think you refer to—because a higher price for flowing gas will lessen the capital supply problem at the time it makes exploration more attractive.

Isn't it true, though, that even if you get a higher price and, therefore, additional supply of capital, that additional capital would not be invested in exploration for gas for the interstate market unless the profit pros-

pects or the return prospects for that gas were better than any other prospects of comparable risk anywhere else?

A. Well, I think we discussed this question in maybe a little different context earlier, and your reference to profitability anywhere else, I thought I also had responded to that question to say that, no, I do not agree that it has to be the highest return anywhere else in perhaps the whole wide world.

We are currently drilling wells, even under the price conditions in existence today, and certainly it could be expected that if the price of gas increases, we will certainly increase our exploratory effort.

PRESIDING EXAMINER: Would any of the funds realized from the increase in the price of gas be specifically earmarked for the exploration and development of gas wells?

THE WITNESS: Not specifically in the sense of doing it

[3,892]

blindly.

Certainly as I indicated earlier, we have additional drilling prospects in our portfolio, and many of these are considered marginal under prevailing prices and prevailing conditions.

Given a higher price for gas, we will take another look at those prospects, and there is a good likelihood that many of them previously considered marginal will now become attractive.

PRESIDING EXAMINER: You would get the same result by increasing the price of oil, too, wouldn't you?

THE WITNESS: With respect to the increase in the price of oil, yes. The same result would also exist in respect to drilling of exploratory wells for oil. But as we indicated earlier, we are completely aware of direction-

ality. We can certainly take—we certainly would look at gas well prospects alone as well as looking at oil well prospects alone.

Any source of revenue, whether it be from gas, gas liquids or oil, would help in the capital supply problem.

PRESIDING EXAMINER: Suppose you had a choice of exploring—or of digging a well in one place where you would expect to find oil and another place where you would expect to find gas. Which one would you put the funds in?

THE WITNESS: Well, if today both of those projects or both of those prospects were being held up because they were marginal and if we had an increase in the price of gas, I am

[3,893]

sure we would drill the gas prospect.

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BY MR. MORROW:

Q. Now, are you now telling me that if you have an increase in the price of gas and additional capital coming from the increase in price of gas, this additional capital will still be allocated just exactly like you have always—you described yourself as having always allocated capital funds and that they are started from the company pool and go down through the divisions and end up in the project which looks like it is going to make the most money for the company?

[3,894]

A. I believe I stated in my prepared testimony that should there be an increase in the price of natural gas, we would first look at all of our prospects in our port-

folio in the Oil and Gas Division, and if there were more prospects under the new conditions of higher price, that we would then go back to this total pool of funds and perhaps through allocation of other divisions of the company get additional moneys to put into oil and gas exploration.

Q. Yes, sir, I know you said that but that is not my question now. My question now is if you have additional capital funds and it turns out that marketing is going to be more profitable, including the comparison of risks, than your Oil and Gas Division, then those additional funds would go into your Marketing Division even if they came from an increase in the price of gas, wouldn't they?

A. Yes, sir, but it would also apply to revenues derived from the sale of motor gasoline. Those funds could go into gas and oil exploration.

Q. So you are saying that if the price of gasoline at the station pump increases, that this might result in an increase in gas exploration?

A. It would give you the funds available for such exploration, but it would not change the viability of the project unless you also increased the prices of the products that go along with them.

[3,895]

Q. And whichever it is, you select the most profitable alternative?

A. Under the definition that I made before in answer to a similar question, and assuming that all conditions are fully considered, including the risk, yes, we feel it is our obligation to our stockholders to invest our money in the most profitable ventures.

[3,895]

Testimony of Kenneth C. Vaughan

Q. All right. And so it is possible—once more and then I will quit asking you. It is possible that higher gas prices, or the returns from higher gas prices could be siphoned off into other parts of your company?

A. Well, in answering that question, I would still like to relate that we are——

Q. May I ask you to answer it yes or no and then——

MR. REBMAN: Well, Your Honor, I think that is perhaps an unrealistic question in a world of uncertainty. Anything is possible but the witness, I think, should answer it with whatever explanation he deems appropriate.

MR. MORROW: I want him to but I would like to have a yes or no answer first.

THE WITNESS: I will first answer your question by yes and then I will quickly add that we are currently drilling wells, even under present price conditions, and to me this is proof that there are in existence a great many additional prospects that are just over on the marginal side that would

[3,896]

immediately be picked up through the vehicle of a higher price increase. And that if you look at total capital allocated to the Oil and Gas Division over a long period of time in our company—and I believe this would be true to others—you will find that we get far more than our share of this capital allocation. So between that capital allocation and the fact that we are currently doing this, even under the very severe conditions of price nowadays, to me would be—I think it could logically be stated that we would be doing additional exploration tomorrow with increased prices.

BY MR. MORROW:

Q. All right. Now, would you turn to page 1766 where you are completing your answer on how to narrow the gap between supply and demand. And as I understand your testimony, you are recommending what you term an alternative fuel price concept.

Do I correctly—and that is at line 10, that term is used.

Do I correctly understand that what you mean is that natural gas should be allowed to rise to a price level at which its prices at the burner tip will be competitive with the prices for alternative energy sources at the consumer level?

A. Well, what I am suggesting in light of the 16 years of failure with respect to an attempt in the regulation of producers by the so-called rate base cost of service concept, is that we are proposing that the Commission, among other things

[3,897]

look to the market place for guidance that we think will provide very logical guidance.

What we are suggesting is not a simple problem. We recognize in making this suggestion that it is a complex one. But we also feel that seeking—that it would be even more in the public interest, more in the interest of the consumer to attempt to devise a regulatory system at the consumer level. Certainly they would be in close proximity to the consumers that regulation is supposed to protect.

I stated earlier that it is my opinion that the gap or the deficiency in supply cannot be met under prevailing conditions and that it can only be met in the future through a combination of competitive prices in the free

market place and the resultant reduction in the growth of demand.

Q. Well, your alternative fuel price concept sets forth virtually the same factors which would serve to establish the price of gas in an unregulated market, don't they?

A. Yes, but I am not suggesting an unregulated market. I am making the suggestion of not complete freedom with respect to gas in the market place. I can assume that the Commission in their expert judgment will select those factors from the market place that are meaningful and that will give them assistance in determining what a just price for gas would be in a competitive market. Regulation is still going to continue, I can only assume, on the other end of the consumers' line of activities,

[3,898]

in our contract negotiations and in our certificate proceedings, and, as a matter of fact, even indirectly through the jurisdiction of the Commission over the natural gas transmission lines.

I am not suggesting deregulation. What I am suggesting here is a method which I think is absolutely essential if we are to ultimately balance supply and demand.

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[3,913]

What I am saying is that the normal regulatory methods applied to utilities simply will not work under the present conditions, and that we do feel, however, that regulation could be effective, would have a good chance of being effective that could ultimately get supply and

demand in balance if they will go to the market place for some guidance.

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[3,915]

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A. Yes, indeed. Our confidence is not at the highest ebb as a result of our past experience, and certainly we would look very hard at whether or not we fully could anticipate those prices and perhaps even the fixed escalations that went along with that price.

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[3,918]

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When you increase the prices of natural gas it could very well be that you can increase both the ultimate recovery and the deliverability of the field with additional wells that could

[3,919]

then be justified, I don't believe that this would be put in the category of many, but I am certain that there are such fields.

Q. Would these be fields that are already connected to a pipeline?

A. Yes, sir.

Q. And you say that if the price for the gas coming from that field were to be increased then you could justify drilling additional wells in that field?

A. Yes, indeed. This is one of the reasons that we indicated the importance of an increase in the price—one of the many reasons why we indicated the impor-

tance of the increase in the price of flowing gas. There are many reasons. This is one of them.

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[3,923]

Q. Mr. Vaughan, during the cross-examination by Counsel Mattingly and by Counsel Morrow a number of questions were posed to you concerning the directional search, and at one point in your answer to that series of questions you made the statement depth is a factor. Would you explain in the context of that questioning what you meant when you said depth is a factor?

A. Yes, sir. Wells below a specified depth in say South Louisiana, wells below a 15,000-foot depth in all probability would be drilling for gas, or gas condensate. There are some areas in the United States where this might not hold, but generally speaking, the probability of finding gas increase with depth, particularly after you leave the, oh, twelve, thirteen, fourteen-thousand-foot level, the variations being due to the—some variation in the areas involved.

Q. And in those circumstances when you are drilling to depths below 15,000 feet, does your economic analysis include a consideration of revenues expected from oil?

A. In the case of South Louisiana, they would probably be confined to gas and the liquid products that come along with the gas.

Q. All right, sir.

* * * *

[3,925]

* * * *

Q. If in fact that is Union's practice as you testified, what, then, does your testimony concerning flowing gas

price have to do with the bringing forth of new reserves?

A. Well, as I indicated in my prepared statement, I feel that this is probably the most important single catalyst with respect to an accelerated exploratory program.

[3,926]

In answer to one of Mr. Holtzinger's questions pertinent to additional development drilling, this would be one factor. But there are a great many others equally important.

The need, or perhaps the recognition for higher natural gas prices I think also must recognize that past field prices have been too low to elicit supply. Correcting that past mistake by increasing the price of flowing gas will go a long ways toward furnishing the capital that we consider necessary to conduct the magnitude of the program necessary in our exploratory venture. And certainly, among other things, would restore a great deal of confidence to the industry.

There are other factors. Any time you increase the price of flowing gas you immediately increase the economically recoverable reserves, since you extend the life of those reserves. * * *

* * * *

[3,928]

* * * *

Q. Going to your testimony with respect to flowing gas and the likelihood that an increase in flowing gas prices would increase reserves. Are there any reservoirs in major fields in Southern Louisiana, to your knowledge, that are at a state of depletion wherein compression facilities are required to produce the reserves?

A. Yes, sir, there are such fields. And in addition, there are naturally flowing fields that will actually flow for their whole life, but fields that have been somewhat captured by heavy inflow of water. And increasing the price of natural gas will allow you to extend the flowing life of those wells and to

absorb any additional costs involved in separating the water and in disposing of the water.

So even in South Louisiana, not to the same degree as the example I gave you in Hugoton, but certainly there is no question that even in South Louisiana, there too you will increase the economically recoverable reserves if you raise the price of natural gas.

Q. Are any such fields being operated today by Union where you could increase the reserves by an increase in the flowing gas price?

A. Yes, sir, we have many fields, many wells that are approaching depletion.

Q. In connection with the installation of compression facilities, is that normally covered under some feature or other of the gas sales contract with the pipeline purchaser?

A. Not normally.

• • • •

[3,993]

PRESIDING EXAMINER: Mr. Harkaway.

FRANK E. BAKER

the witness on the stand at time of recess, resumed the witness stand, and, upon examination testified as follows:

CROSS-EXAMINATION (resumed)

BY MR. HARKAWAY:

* * * *

[4,002]

* * * *

Q. With regard to the gas reserve figures, haven't many fields in the past increased in size as a result of developmental drilling from what their first estimate was?

A. That's right.

[4,003]

Q. Most have; is that right?

A. Yes.

Q. And have you taken this into consideration in estimating future reserves availability to pipeline companies?

A. That is right. Our average annual projected finding rate for South Louisiana as well as the rest of the report takes into consideration extensions and revisions which make up a good portion of the annual reserve findings. These have made up a considerable portion of the reserve findings in the past and we hope they will in the future.

Q. In fact, have not the AGA reserves as reported in 1968 and '69 been reduced as a result of revisions?

A. That is one of the major causes, but discoveries have also been lower than normal, if I remember right.

Q. Do you know upon what the revisions downward were based? The AGA revisions?

A. No, I do not. But the recent press releases on the interstate gas supplies also indicate a similar condition, 3.8 trillion cubic feet of reserves downward revision were reported in the Permian Basin Area.

Q. Which report was that?

A. Excuse me. I will get it.

Q. I didn't mean to interrupt your answer, Mr. Baker, but I just missed what you had said.

A. Yes. It is a press release dated July 1, 1970, on

the interstate gas supplies.

Q. That is a Federal Power Commission press release?

A. That is right.

Based on the 1969 Form 15 filings.

Q. This press release to which you have made reference is a result of the Form 15 reports; is that correct?

A. That is right.

MR. HARKAWAY: Might I have just a moment, your Honor.

BY MR. HARKAWAY:

Q. Mr. Baker, you made reference to I think a 4.8-trillion-cubic-foot figure; am I right?

A. I believe I said 3.8 trillion cubic feet for the Permian Basin.

Q. Oh, I see. You show a drop of 3.8 trillion cubic feet, approximately, in the Permian Basin. You show

an increase of about 3.8 trillion cubic feet in the offshore South Louisiana area; is that correct?

A. That is right.

Q. Does this increase in South Louisiana affect your deliverability study in South Louisiana?

A. No, it does not.

Q. Do you know the reasons the pipelines have shown this revision downward of reserves in the Permian Basin?

A. I can only speculate.

Q. You have not made any study of it; is that right?

[4,005]

A. No, I have not.

Q. Do you know if the staff has made any study of it?

A. If they have, I am not aware of one.

Q. Mr. Baker, the press release to which we have just referred shows a reduction in the Oklahoma and Anadarko of about 85,000 MMcf. Is that correct?

A. Yes.

Q. Would you take this to show a continuing decrease in reserves in the Hugoton-Anadarko Area?

A. No, not necessarily.

Q. What other part of that press release might refer to the Hugoton-Anadarko Area?

A. I don't think it is mentioned other than this.

Q. According to your study, the Hugoton-Anadarko has been decreasing in production; is that correct? Page twenty-five of the study?

A. Production decreased in 1969—or excuse me, 1968.

Q. And do you have any figures to indicate whether or not there has been an increase in reserves in the Hugoton-Anadarko Area?

A. Just a moment.

[4,005]

Testimony of Frank E. Baker

Mr. Harkaway, may I ask whether you are speaking of Form 15 reserves now, or AGA?

Q. Well, let me ask you. Is there necessarily an inconsistency between the two?

[4,006]

A. Not that I know of. But I have not made a study of the Form 15 reserves for that particular area.

Q. According to the AGA reports upon which you have relied, has the reserve picture in the Hugoton-Anadarko been diminishing?

A. Yes.

Q. And would the Form 15 report—press release which you have just showed to me tend to corroborate that?

A. What you pointed to awhile ago was not the complete Hugoton-Anadarko area.

Q. Would you mind expanding, then, upon the area you think is in Hugoton-Anadarko for this purpose?

A. Yes. As listed in this press releases it is divided up into the Oklahoma Panhandle, Oklahoma Anadarko, and Kansas. And each one of these areas show decreases in reserves.

Q. So that for the Oklahoma and Kansas, Hugoton-Anadarko Area there would be on that basis reductions in reserves; is that right?

A. Yes, sir.

Q. Are you familiar with deep drilling that is now being undertaken in the Hugoton-Anadarko Area?

A. Yes, I am.

Q. Do you know of any reserves that have been reported as a result of that deep drilling?

A. Yes. There have been several applications which I

[4,007]

am not conversant with to the Federal Power Commission in the last—possibly the last two years by the interstate pipeline companies to attach deep reserves in the western portion of the Anadarko Basin.

Q. Would this tend to show the likelihood that in fact there are new reserves being developed in the Hugoton-Anadarko Area?

A. That's right.

Q. And would those have been reported by the AGA or in the Form 15 Reports?

A. They would have been reported, I assume, in the AGA reports, and they are reported in the Form 15 Reports as the reserves are certificated to the pipeline companies.

Q. Do you know whether or not any for which applications have been made have been certificated so that they would be in the Form 15 reports?

A. No, I would just be guessing.

Q. If an application has not been certificated, it does not become part of the Form 15 gas supply for a pipeline company; is that right?

A. That's right.

Q. What happens? Does it just hang in limbo until it finally becomes certificated?

A. That is the way I understand it.

Q. And are there such applications—were there such

[4,008]

applications pending in the South Louisiana Area at the time you made your study?

A. I can't say for sure, but it seems reasonable to believe that.

[4,008]

Testimony of Frank E. Baker

Q. Then they would not have been included in the study insofar as your use of Form 15 was concerned; is that right?

A. That is right.

Q. In the projections of increased gas in the future, did you take into consideration at all the price at which that gas would be sold in interstate commerce?

A. No, I did not.

Q. So that if there were changes in the price, it wouldn't affect your estimate; is that right?

A. No, it would not.

Q. Do you know whether AGA in making its reserve estimates—the AGA committee used an economic criterion to determine whether or not reserves were commercially producible?

A. I understand that that is one of their criteria.

Q. And I would assume—would you assume that if the price were higher or lower it might have an effect upon their estimate of what is commercially producible?

A. I would think it would have some effect, but I would have no idea to what extent.

Q. You don't know what it would be. You really don't know what the limit of commercial productivity—producibility

[4,009]

by the AGA committee was either, do you?

A. No, I do not.

Q. Did you take into consideration whether any of the producers' exploratory programs and changes that might take place in them would have an effect upon the reserves available in the future?

A. Well, we certainly hope that additional drilling would increase findings in the future over the rate that

we have projected, but we had no reason to consider that as part of our projections.

Q. In your projections, then, you did assume as an underlying assumption that there would be a standstill, in effect, in exploration and development?

A. We thought that that was being at least possibly optimistic because of the downward trends in drilling and the bad year of reserve additions that took place in '68.

MR. NORRIS: I hesitate to interrupt, Mr. Harkaway, but with your permission, when you spoke of a standstill did you mean at current levels, a further decline, or a complete halt in all exploration? I think for clarity in the record we ought to define standstill.

MR. HARKAWAY: I think the witness' response clarifies my question.

MR. NORRIS: Well, then, may I ask the witness what he meant by standstill, or how he understood it.

[4,010]

THE WITNESS: I understood it as continuing the present trend as we projected for the last five years on annual reserve additions.

MR. HARKAWAY: I think the witness and I understand each other, Mr. Norris.

MR. NORRIS: I wanted to be sure the record so reflects.

PRESIDING EXAMINER: All right, next question.

MR. HARKAWAY: May I have the witness' earlier response read?

(Answer read)

[4,010]

Testimony of Frank E. Baker

BY MR. HARKAWAY:

Q. Did you consider at all in your study the possibility that the Interior Department would make additional leases available offshore Louisiana?

A. Yes, we did. We figured that that is necessary to maintain reserve additions at the level that they have been for the past five years.

Q. What assumption did you use insofar as leasing by Interior?

A. None.

Q. Then I think I misunderstood your response to my question.

THE WITNESS: May I have his question again, please?

(Record read)

THE WITNESS: Excuse me. I say yes we did, to the extent

[4,011]

that we considered it necessary for a new leasing program to go into effect in order to have reserve additions at the level that they have been in '64 through '68 average.

BY MR. HARKAWAY:

Q. Did you make any study to determine whether existing leases had been drilled by producers?

A. No.

Q. You don't know whether some existing leases have not in fact been drilled by producers holding those leases?

A. Well, I know that there is probably some, but I haven't made a study of it.

MR. HARKAWAY: Thank you, Mr. Baker. That is all I have.

BY MR. GOLDBERG:

Q. The figures you used, then, wouldn't reflect the extent to which reserves may be available under existing leases that haven't been drilled. Is that right?

A. Pardon me, sir. I did not quite understand.

Q. The figures that you have used in making your projections and reaching your conclusions do not reflect the extent to which reserves may be available under leases held by producers in Southern Louisiana that have not yet been drilled; is that right?

A. That's right.

Q. You have indicated a responsibility for certain portions of Exhibit 9, and they didnt' include page two. Do I ask

[4,012]

Mr. Zareski questions about page two, or may I also address questions about page two to you because you share the responsibility for statements on that page?

A. It is my understanding that Mr. Zareski would answer questions on this part of the report.

Q. All right.

On page eighty-six of Exhibit 9, you indicated that manner in which you approached the subject of estimating productive capability for Southern Louisiana, and in your responses to questions by Mr. Harkaway you identified the three major interstate pipeline companies that you used. And I think you indicated did you not, the reason why you didn't use the totality of the pipeline companies in the Southern Louisiana Area was because of time; you didn't think you had enough time to do that, is that right?

A. That is partially right. The reason we didn't do it was because we thought the three companies we were

using and the number of sources would give use a reliable sampling for the South Louisiana Area.

Q. But by using all of the companies you could have eliminated any question about this representativeness; isn't that right?

A. That is possibly true.

Q. Did you make any effort to determine productive capability by using any other combinations of companies other

[4,013]

than Transco, Texas Gas, and Michigan-Wisconsin?

A. No, sir.

Q. I believe you testified that the criteria that you used in selecting those three pipeline companies was that each had old and new reserves, reserves onshore and offshore, and large and small reserves. Is that right?

A. Yes, sir.

Q. Isn't that generally true of each of the other pipeline companies that were available to you for use?

A. Yes, sir.

Q. Then how did those criteria help you to select Transco, Texas Gas, and Michigan-Wisconsin rather than some other combination?

A. I don't know. These are the three companies I decided to use because to me they represented a representative sample.

Q. Well, was your decision based simply on those criteria that I recited to you which I thought you had recited earlier to Mr. Harkaway?

A. Yes, sir.

Q. I believe you indicated that you began the study sometime in 1968; is that correct?

A. That is correct.

Q. Early 1968, was it?

A. It began late Summer of 1968. Pardon me just a minute. All the responsibility I have in the report, in my

[4,014]

own particular portion of it.

Q. Yes, that is what I was referring to. Late Summer of 1968. And I don't believe you indicated when you concluded your task.

A. The majority of it was finished, oh, by mid-summer, 1969.

Q. And the balance of it?

A. Certain portions were completed possibly as late as August.

Q. On page 1103 of the transcript you indicate the purpose of the study. When you talk about the purpose of the study there you are talking about the totality of Exhibit 9; is that correct?

A. No, sir. That was just for this one particular study on South Louisiana.

Q. I see.

Do I ask you about the purpose of the study in its totality, or do I save that for Mr. Zareski?

A. Mr. Zareski.

Q. All right.

In connection with the portion of the study for which you were responsible, was that done under the supervision and direction of Mr. Zareski?

A. Yes, sir.

Q. Did you receive your assignment from him?

[4,015]

A. Yes, sir.

Q. And did you receive your assignment from him late in the Summer of '68?

A. Yes. It was sometime during the Summer of '68.

Q. And did he express to you the purpose of the assignment?

A. Not in exact words.

Q. Was this a study initiated at staff level or was it at the direction of the Commission?

A. As far as I know it was initiated at the staff level.

Q. Do you know why it was initiated?

A. No, I do not.

Q. Do you know why it was issued in September, 1969, rather than not at some other date?

A. No, sir.

Q. Is it possible to sustain future production at historical rates of growth and annual reserve additions simply by price adjustment?

A. That would depend on the amount of annual reserve additions that price adjustment brought forth, I suppose.

Q. Have you addressed yourself to that question?

A. No, sir.

Q. When you received your assignment from Mr. Zareski, did you receive from him any instructions as to how you were to proceed?

A. No, sir. I was just supposed to look into the situation and make comparisons on an area level if I could with available data.

Q. I believe you used in part AGA data, correct?

A. Yes, sir.

Q. Did you communicate with AGA for the purpose of securing the raw data which is behind the published reports they make?

A. No, sir.

Q. Do you know whether anybody else in the Commission did?

A. Not to my knowledge for the purpose of this report.

Q. Is there any implication in the portions of the report for which you are responsible that your findings are attributable to the price practices of the Federal Power Commission?

A. I don't think so.

Q. And you didn't intend any such implication, did you?

A. No, sir.

Q. Just so we have no confusion, my old habit of asking it in the wrong form leaves an ambiguity.

Did you intend an implication that pricing policies of the Federal Power Commission have produced declining rates of additions of reserves?

A. No, sir.

[4,017]

Q. At page 1103 of the transcript you note that by 1969 South Louisiana Area had supplied thirty-three percent of the total United States gas production, which was an increase over 12.8 percent in 1956. What are the reasons for that jump?

A. Well, primarily the increase, the growth of the South Louisiana reserves that were available. Some of the other areas are better established; they had no large available sums of gas to warrant building additional pipelines, with the exception, perhaps, of the Permian Basin and the Texas Gulf Coast during this period. It was just a good supply of gas to be attached, I assume.

Q. Is the phrase "critical R/P ratio" a term of your invention?

A. Yes, sir.

[4,017]

Testimony of Frank E. Baker

Q. Do you know whether it has ever been used any place else other than in this study, Exhibit 9?

A. I have no idea.

Q. What makes it critical?

A. Well, based on our definition, which—well, essentially the definition of critical R/P ratio is when an area —gas supply area no longer sustains production at historical rates of growth of production and gas reserve additions. What we were trying to point out here is that the United States as a total is relying more and more on South Louisiana. We projected the production at historical rates. We did not project the reserve additions

[4,018]

to increase because they had not shown such a tendency in the last five years. What we wanted to know was if the conditions for the next five years continue as they have for the last five years, what possible point in time would a problem exist. And the critical R/P ratio term just fell out of this study. It was at the time when our productive capability could no longer sustain increased production at the historical rate.

Q. According to your Exhibit 9, even when that point in time is reached production may increase nonetheless, but it won't be at the historical rates; is that right?

A. That is right.

Q. Based upon your definition of critical R/P ratio, that point in time is inevitable in any producing area, is that right?

A. As I understand it, the way we defined the term; yes, sir.

Q. And you have determined that it is inevitable in eight years in Southern Louisiana?

A. No, sir. I said that the problem would come sometime I believe it was in 1973. At that time the area will happen to have an R/P ratio of about 8 if the production increases as we have projected and if reserve additions continue as they have.

Of course, if reserve additions are less, we could have this point being reached at an earlier period. And if production

happens to turn out less than we have projected, this could be extended.

Q. Is it possible to have a permanent rescue from reaching a critical R/P ratio in an area?

A. I certainly hope so.

Q. You think it is?

A. Yes, sir. If reserve additions are great enough, this can be held off for some time.

Q. And does that depend only upon price or whether the reserves are actually in the ground?

A. It would depend on whether the reserves were available. And I don't know about the price.

Q. Now, this critical R/P ratio has been determined as the result of the function of a number of variables, one of which is demand; is that right?

A. Yes, sir.

Q. And that would be reflected on Figure 6 on page fifteen; is that right?

A. Yes, sir.

Q. This estimated productive capability that you show on Figure 6, that is based upon those three pipeline companies, is that right?

A. That's right, sir.

Q. And the demand projection makes no effort to determine, does it, whether some of the demands should be met by other

[4,020]

forms of energy other than natural gas; is that right?

A. This particular demand estimate would require that the demand be met by natural gas for this particular study.

Q. Well, do you have boiler fuel, for example, in that demand projection?

A. Yes, sir.

Q. You haven't attempted in this study to make any determination as to appropriate allocation of demands among various sources of energy.

A. No, sir.

Q. You haven't concerned yourself with the most economical allocation of resources; is that right?

A. That's right.

Q. Nor has your study attempted to develop what the gas supply sitaution might be in terms of a national energy policy; is that correct?

A. That's correct. We have not.

Q. Although your study recognizes, does it not, that such a national energy policy is a fundamental requirement in determining the proper relationship of demand and the energy resources available to supply those demands?

MR. NORRIS: May I have a transcript reference to that, please, counsel?

MR. GOLDBERG: I think it is in the study itself.

MR. NORRIS: Could I have the question read back at the

[4,021]

same time, then, please?

(Question read)

MR. GOLDBERG: If I am going to have to give you a reference right now before that question can be answered, then I will have to simply withdraw it until I can find it and then come back to it.

MR. NORRIS: That would be acceptable.

PRESIDING EXAMINER: All right.

MR. GOLDBERG: I don't know that the Examiner has asked me to do that yet.

MR. NORRIS: Well, would you desire for me to speak to it, your Honor?

PRESIDING EXAMINER: You just volunteered to do that, did you not?

MR. GOLDBERG: No, I didn't volunteer. I said if that becomes a requirement I am going to have to withdraw the question until I can point that out in the record.

MR. NORRIS: Well, the problem I have, your Honor, is that I have not to my recollection seen that this national emergency policy is a fundamental requirement for the study.

Now, if counsel is correct and if it is in the report, then a proper predicate would have been laid for the question. However, to this point in time I have not seen that reference, and until counsel is able to furnish me with it, I think the question is objectionable.

[4,022]

PRESIDING EXAMINER: I think you would lay all doubt to rest if you found the reference.

MR. GOLDBERG: All right. I will just hold that question.

I think the reference that has just been brought to my attention is good enough. I would refer to the first full paragraph on page forty-one of Exhibit 9.

MR. NORRIS: Your Honor, this witness hasn't taken any responsibility for page forty-one, unless I misread his direct testimony.

PRESIDING EXAMINER: What is the question before me?

MR. GOLDBERG: May we have it read, please.

PRESIDING EXAMINER: It might be easier if you repeated it.

MR. GOLDBERG: All right.

BY MR. GOLDBERG:

Q. In considering the policy that should be followed with respect to meeting demands through the use of natural gas, the report indicates it involved a consideration of the utilization of other forms of energy as well. Isn't that correct?

A. Yes, sir.

Q. And this report doesn't get into the use of other forms of energy to meet the demands that you have projected as being met through natural gas; isn't that right?

A. That's right.

MR. NORRIS: I take it Mr. Goldberg is excluding the

portion of the report which refers to LNG and the portion of demand which it might supply, which he cross-examined on this morning.

MR. GOLDBERG: No, I am not excluding anything.

PRESIDING EXAMINER: Well, he has answered the question.

Go ahead.

BY MR. GOLDBERG:

Q. At page 1105, considering the sentence at lines 21, through 23, isn't the thought more appropriately expressed if the sentence were revised to read, I quote, "When the critical R/P ratio is reached, it only means an area can no longer increase annual production at the historical rate," unquote?

A. That's it.

Q. Looking at the testimony at the bottom of 1105 and going over to the top of 1106, you say, I quote, "In the case of South Louisiana, production will continue to increase until 1974 (Table 2; page 16). After 1974 annual production will level off and start to gradually decline."

You are not by that testimony predicting that this will actually occur?

A. No; this is a result based on the assumptions of the study.

Q. It depends upon the validity of your assumptions as to whether or not it will occur, right?

A. That's right.

[4,024]

Q. And this is essentially the fact with respect to most everything that you have set forth in the report for which you are responsible?

A. That's right.

Q. Could the critical R/P ratio be delayed by reducing the demands that are to be met through the use of natural gas?

A. From South Louisiana?

Q. Yes.

A. By theory, so long as the annual production was less than we have projected, it would delay it, yes.

[4,024]

Testimony of Frank E. Baker

Q. You didn't make any analysis of demand to determine what portions of that demand might well be better served by other forms of energy; right?

A. No, sir.

Q. At page fifteen of Exhibit 9 you say, I quote, the significance of the critical R/P ratio is that when it is reached an area can no longer be relied on to deliver its share of increasing U.S. production requirements, end of quote.

How do you determine for South Louisiana, for example, what its share should be?

A. Well, this is based on the historical amount that South Louisiana has in the past provided.

Q. And you haven't in that regard considered whether what it has provided in the past was a disproportionate share of supply that should have come from some other area, for example?

[4,025]

MR. TILFORD JONES: May we have that question read back, please?

(Question read)

MR. NORRIS: Disproportionate to what, counsel?

MR. TILFORD JONES: I object to the question on the grounds it is abstruse, your Honor.

MR. GOLDBERG: This whole report is abstruse.

PRESIDING EXAMINER: What do you mean by a disproportionate share?

Do you mean more than it was required to perform?

MR. GOLDBERG: More than it should have supplied.

PRESIDING EXAMINER: You mean more than it has historically produced?

MR. GOLDBERG: Yes, more than it has historically supplied. He says he based the share on historical supply.

PRESIDING EXAMINER: And he says when it goes

below its historical supply, then it is not living up to its expectations.

MR. GOLDBERG: Well, this is what I gather from page 15.

PRESIDING EXAMINER: All right.

MR. GOLDBERG: That it should continue to supply that share.

PRESIDING EXAMINER: Well, you are saying that—or your question is at its peak wasn't it supplying more than it was supposed to.

MR. GOLDBERG: I would accept that. I would accept that.

PRESIDING EXAMINER: Well, I think this is largely a matter

[4,026]

of conjecture.

MR. GOLDBERG: I suppose it is a question of whether what has happened in the past is necessarily a proper point of reference.

PRESIDING EXAMINER: All right. Next question.

MR. GOLDGERG: All right. We will go to the next sentence, then, on that page, which reads, quote, the resulting deficiency will have to be supplied by other sources, unquote.

BY MR. GOLDBERG:

Q. Is that other sources, that is other areas where natural gas is produced, or do you mean other forms of energy?

A. Primarily other areas where gas is produced, pipeline imports and possibly LNG.

Q. But the resulting deficiency could be supplied by other sources of energy, right? Meaning other forms?

A. That's possible.

Q. On page seventeen you say in the first full paragraph, and I will read only a portion of the sentence, quote, because a time lag of several years exists, and so on. Did you have any particular period of time in mind? What is that time lag?

A. I have no definite period. I just know that it usually—the time from cranking up to drill a well, to complete it, to develop, to sell the gas to the pipeline company usually takes several years.

Q. But you are not quantifying that time?

[4,027]

A. No, sir.

Q. All right. You go on to say in that sentence, quote, it is obvious that action to stimulate exploration must be taken in advance of the time the critical R/P ratio is reached, unquote. Would you define for us that action to stimulate exploration that you have reference to?

A. No, sir, I cannot define it.

Q. You are just saying something has to be done?

A. Yes, sir.

Q. But you don't know what that something is?

A. No, sir.

Q. At page seventeen again, in that last sentence, you say that it is imperative that a proper balance between the productive capabilities of the various areas be maintained.

Have you determined that proper balance?

A. No, sir.

Q. You don't know what it is?

A. No, sir.

Q. In the first full paragraph on page seventeen, I would direct your attention to the first sentence of that paragraph. Doesn't your conclusion in that sentence mean

that you are assuming that the increasing demand on the area must be met and must be met from South Louisiana reserves?

A. Yes, sir, and the reserves that we projected to be added.

[4,028]

Q. And when you speak of the increasing demand on the area, that is part of that demand which is shown in that Figure 6?

A. Yes, sir.

Q. Looking at Figure 7 on page nineteen, the deficiency area that you show up there near the upper righthand corner of the diagram. Would it be fair to conclude, judging by the size of the two areas below that deficiency area, that the deficiency is entirely attributable to new markets?

A. No, sir, I don't think it was so contemplated.

Q. Do you know what portion of that deficiency is attributable to new markets and what portion is attributable to replacing depleted supplies for existing market?

MR. TILFORD JONES: I wonder if counsel would mind defining the term new markets, your Honor.

MR. GOLDBERG: I am using it in exactly the way it is used in the diagram. You notice the phrase "new reserves acquired for new markets."

MR. TILFORD JONES: Very well. Carry one.

BY MR. GOLDBERG:

Q. Just so the record will be clear, let's ask Mr. Baker to tell us how the phrase "new markets" is used in Figure 7. Let's try that first. Would you help us on that, Mr. Baker?

A. Well, as we used it in this particular study, the

new market represents the annual incremental increase in production. We have used that to indicate a new market.

Q. Does that mean that you assumed that the increase in production was to supply markets not previously receiving natural gas?

A. Not completely, no, sir. This was expansion of old markets and—

Q. And new markets?

A. And new markets too.

PRESIDING EXAMINER: We will take a recess.

(Whereupon, the afternoon recess was taken from 3:15 o'clock p.m., until 3:30 o'clock p.m.)

[4,030]

PRESIDING EXAMINER: All right, Mr. Goldberg:

BY MR. GOLDBERG:

Q. Returning to page 19—I think we can do better if we turn to page 20.

Page 20 has Table 3, and Table 3 represents, does it not, the underlying data for the projections on Figure 7 on page 19?

A. Yes, sir.

Q. Can you tell us what portion of the deficiency is represented by the requirements of new markets in the sense of markets that had not previously been supplied with natural gas?

A. No, sir, I could not.

Q. In your use of the term "new markets" in Figure 7, from the definition you have given us, would increased customer usage be classified as new markets?

A. Yes, sir.

Q. On page 15 you have this sentence, I quote: "Normally, decreasing production during periods of increasing demand, like the present, indicates that the period of peak productivity of an area is passed and that the critical R/P ratio has been reached." End of quote.

By using that word "normally," do you mean that the present situation is not normal?

A. Yes, I would say the present is normal.

Q. Is?

[4,031]

A. The present condition is normal.

Q. Is normal?

A. Yes.

Q. Thank you.

Referring you to page 21 of Exhibit 9, you say in the second paragraph that the disappearance of the reserve surplus would mark the end of the natural gas industry's long period of vigorous sales growth.

What do you mean by vigorous sales growth?

A. Well, we were just indicating the recent growth of the total natural gas sales.

Q. Were those the rates you were discussing with Mr. Harkaway, the 12.4 percent? Is that what you mean by vigorous sales growth?

A. No, sir. This actually referred to the overall total U. S. growth.

Q. Would you expect the natural gas industry's sales growth to continue unabated?

A. No, sir. It depends on the price of other energy sources and their availability.

Q. The recent explosion in demand for natural gas is the result of demands for a fuel to meet environmental requirements; is that correct?

A. That is partially it, as I understand it.

[4,031]

Testimony of Frank E. Baker

Q. What other factors have caused that sudden deman for

[4,032]

gas in excess of what was anticipated?

A. I don't know. Possibly an unexpected population growth. More electric power generation, possibly. I haven't studied this end of it.

Q. Would you say that there is a relationship or a correlation between exploration effort and development effort and anticipated demands for the product?

A. I don't know.

Q. Do you think that producers involved in exploration and development would maintain the same degree of activity if they were anticipating a 5 percent rate of growth as against a 10 percent rate of growth?

A. I suppose that would depend on the individual producer and what their needs were and what the make-up of their company was.

Q. Does a producer, do you think, explore for gas in terms of the availability of markets where he can sell the gas?

A. To some extent, yes, sir.

Q. I take it from that sentence I have referred to on page 21 that notwithstanding the disappearance of the reserve surplus you would anticipate continued sales growth, but perhaps not at the same rate that has recently been experienced. Is that right?

A. I suppose it would continue to what extent the reserves—new reserves could support it, because you will

[4,033]

always have some new reserves coming in every year.

Q. At page 23 you are indicating an increase in the

percent of the total U. S. production that is to be shared by South Louisiana production to approximately 40 percent. Is that correct?

A. Yes, sir. This is based on the projecting the requirements at the historical growth rate.

Q. Well, what is the justification for imposing upon South Louisiana production a 40 percent share of total United States production?

A. The 40 percent just happens to fall out of the study where we are projecting the historical growth rate in production for that area.

Q. You are not undertaking to say that South Louisiana production should be maintained at a rate which makes it possible for South Louisiana to take care of 40 percent of total U. S. production, are you?

A. No, sir.

Q. At page 87 of Exhibit 9—the sentence begins at the bottom of 86, actually. You say, quote, "These percentages were assumed to represent the annual productive capabilities during the years of declining deliverability," end of quote. Is South Louisiana in the years of declining deliverability?

A. No, sir. This was meant—not necessarily. This was meant for the individual sources that were used, how they

[4,034]

were scheduled in the Form 15s.

Q. Now, you say on page 87, quote, "It was assumed that this total curve was representative of the South Louisiana area," unquote. That is a reference to the productive capability curve, is it?

A. Yes, sir.

Q. Now, when you say that was assumed, you are not to be understood as saying that that is in fact representative of the South Louisiana area?

A. We assumed that it was representative of the South Louisiana area.

Q. But is it?

A. I know of other sources—other studies which used moreorless this same method which used all 11 companies taking gas out of South Louisiana. I think it is about 98 percent of the gas that is dedicated to these companies in South Louisiana was used in that study, and their capability—or their productive capacity for 1969 was essentially the same as the one we used in our report.

Q. Are you now relying on some other unidentified studies to support what you did?

A. No, sir.

Q. If you are not relying on those studies, let's put those out of consideration, and I ask you to tell me where the proof is that your assumption squares with the fact.

A. Based on my experience working with the pipeline gas reserves in South Louisiana, I consider this to to be a representative sample.

Q. Is any of the alleged shortage of natural gas a function of deliverability? Or attributable to deliverability problems, if you know?

A. It could possibly be on a local basis, but I don't think it is over-all, no, sir.

Q. Have you investigated that area?

A. Not in this particular study.

MR. GOLDBERG: That is all we have. Thank you.

PRESIDING EXAMINER: Mr. Norris?

BY MR. NORRIS:

Q. Mr. Baker, my name is Robert L. Norris. I represent Humble Oil and Refining Company in these proceedings. And before I get to my cross, I will try to cover a few things which Mr. Goldberg and Mr. Harkaway raised for me.

First, it was my understanding this morning that you testified that it took you approximately two days to select the companies which went into your Southern Louisiana deliverability study, and that actually more time went into the study itself. Am I correct in that?

A. That is right.

MR. HARKAWAY: Excuse me, Mr. Norris. Did you say to select the companies took him two days? And he said that is

[4,036]

correct?

MR. NORRIS: That is correct. That was my understanding, and I thought the record was not completely clear on this.

I take it Mr. Harkaway is going to have an additional question for you.

PRESIDING EXAMINER: As I understood it, what I thought he said was it took him two days to review the Form 15s which related to each of the companies he selected. Is that more nearly what you said this morning, or did you say it took you two days to actually select the companies?

THE WITNESS: I don't exactly remember how I stated it, but it took me two days to review the data in order to select the companies.

PRESIDING EXAMINER: That is what he said. Not to select the companies. To review the data which related to these companies.

MR. NORRIS: Well, let me ask another question, then.
PRESIDING EXAMINER: By all means.

BY MR. NORRIS:

Q. In reviewing the data in order to select these companies, you spent some two days. The actual study of these companies took some greater amount of time; is that correct?

A. Yes, sir. Approximately two months.

Q. Two months to make the deliverability study as to these three companies?

A. Yes, sir.

Q. As a preliminary matter, Mr. Baker, it is my understanding that you are a geologist and you have had from time to time occasions to prepare reserve estimates.

A. Yes, sir.

Q. From the ground up. And just for the benefit of the record, would you explain to us the process which a reservoir engineer or geologist goes through in preparing a reserve estimate? How it is built up?

A. Well, first, at the——

MR. HARKAWAY: Just a moment.

Your Honor, I must object to this unless the witness lays—or Mr. Norris lays a foundation that the witness in fact did make such reserve estimates in his studies. I think the witness has already testified that his reserve estimates were the reserve estimates of the AGA, and not his own.

MR. NORRIS: That is not the purport of my question. I am speaking of the fact that the witness on Transcript 1102, line 3, said, speaking of his work with the Federal Power Commission, "My assignments con-

sisted primarily of analyzing gas reserves and deliverability studies stubmitted to support pipeline certificate applications." And his testimony indicates that he is capable of making a reserve estimate.

Now I would like—

PRESIDING EXAMINER: His testimony here says that he

[4,038]

reviewed the—or analyzed the gas reserve and deliverability studies made by others, not that he himself made.

BY MR. NORRIS:

Q. Was it necessary in this work for you to prepare independent estimates of these reserves that were submitted by other parties, Mr. Baker?

A. Yes, sir, occasionally.

Q. Would you please indicate for the record the process which you followed in estimating reserves?

MR. HARKAWAY: Mr. Examiner, once again I object, unless Mr. Norris is trying to establish the qualifications of the witness. And if that is what he is trying to do, we certainly are willing to stipulate to them.

PRESIDING EXAMINER: Are you questioning his ability to make these studies?

MR. NORRIS: No, sir, I am not questioning his ability to make them. I thought it would be helpful to indicate the process by which these estimates are made.

MR. GOLDBERG: Why would that be helpful, Mr. Examiner?

MR. NORRIS: I think it will become apparent with further questions, Mr. Goldberg.

PRESIDING EXAMINER He didn't make the estimates himself. He reviewed the estimates made by others, according to what he says here. Isn't that correct?

[4,039]

THE WITNESS: Yes, sir. In the case of this report.

BY MR. NORRIS:

Q. Mr. Baker, in reviewing estimates of natural gas reserves would it be correct to state that two geologists or reservoir engineers working with the same basic data would arrive at different estimates of the magnitude of the reserves in a particular prospect or instance?

MR. GOLDBERG: I object to that. I would like to know what is the relevance of a question that two geologists might arrive at two different results, and how is that contributing to the record?

PRESIDING EXAMINER: Well, maybe the result is subject to some elasticity. I mean the fact that he comes to some result doesn't make it conclusive, and I guess that is what Mr. Norris is trying to show.

MR. GOLDBERG: Maybe he is trying to—

PRESIDING EXAMINER: All right, you can answer the question.

THE WITNESS: It is correct that two geologists using the same data would probably not come up with exactly the same estimate.

BY MR. NORRIS:

Q. Would an acceptable or a reasonable margin of error be, say, plus or minus ten percent?

A. Yes, sir, I think that would be reasonable.

[4,040]

PRESIDING EXAMINER: I don't know if you classify it correctly when you say "margin of error." It is not considered an error if there is a difference of ten percent.

MR. NORRIS: The margin of variance, would ten percent be reasonable.

BY MR. NORRIS:

Q. If you will turn to page 21 of Exhibit No. 9, Mr. Baker. And referring to the last sentence on that page you state, and I quote, "The AGA's 1968 report revealed that in certain areas there had been large downward revisions of prior reserve estimates." Have I quoted that correctly?

A. Yes, sir.

Q. First, let me ask you, what do you mean by large, Mr. Baker?

A. Well, anything substantial, that is larger than normal.

Q. Do you have a copy of the 1968 report of natural gas reserves published by the AGA?

A. Yes, I do.

Q. That is a report entitled "Reserves of Crude Oil, Natural Gas Liquids and Natural Gas in the United States and Canada as of December 31, 1968"?

A. Yes, sir.

Q. Would you please turn to page 120 of that report. Do you have that page, Mr. Baker?

A. Yes, sir.

[4,041]

Q. Is that page entitled "Table 1: Estimated Total Proved Recoverable Reserves of Natural Gas in the United States"?

A. That's right.

Q. Mr. Baker, the fourth column on that page is entitled "Revisions," is it not, under "Changes in Reserves During 1968"?

A. Yes, sir. Excuse me. If you are counting the states and so forth, that is the fourth column.

Q. Yes, sir. If you would refer to the column entitled "Revisions."

A. Yes, sir.

Q. And in that column, certain negative figures appear for revisions, do they not?

A. Yes, sir.

Q. Would you accept subject to check, Mr. Baker, that the negative revision of 77,751 shown for the State of Arkansas during 1968 amounts to 2.7 percent of the reserves as of 12-31-67?

A. Yes, sir, I would.

Q. And that the downward revision of 58,353 shown for California is not expressable as a percentage without going several places to the right of the decimal?

A. Yes, sir.

Q. That the downward revision shown for Colorado of 75,824 represents 4.2 percent of the 1,769,263 millions of cubic

feet shown as reserves as of 12-31-67?

A. Yes, sir.

Q. That the downward revision for Indiana represents 1.3 percent of the reserves as of 12-31-67?

A. Yes, sir.

Q. That the downward revision for Mississippi of 13,743 represents less than one-tenth of one percent of the reserves shown for Mississippi as of 12-31-67?

A. Yes, sir.

Q. And that for Montana, the downward revisions are less than one-tenth of one percent?

A. Yes, sir.

Q. That for Oklahoma the downward revisions of 715,-963 Mcf represent only 3.7 percent of the 19,403,806 million cubic feet reserves shown as of 12-31-67?

A. Yes, sir.

Q. That for Texas, including the off-shore, the downward revisions of 1,757,758 represent only 1.4 percent of the reserves as of 12-31-67?

A. Yes, sir.

Q. And that for Utah the downward revision of 30,-647 represents only 2.5 percent of the 12-31-67 reserves for that state?

A. Yes, sir.

Q. Then in view of the magnitude of these changes, would

[4,043]

you still say that there had been large downward revisons in 1968 in AGA numbers?

A. Well, these figures are just the downward revisions it actually shows. And that means that obviously there was probably some upward revisions in the same areas. So if this is the case, you get a resultant downward revision, and the actual downward revisions that show up here probably reflect a much greater downward revision in any one of these areas.

Q. However, the report itself does not indicate large downward revisions reading from the face of the report, does it, sir?

A. Excuse me.

MR. HARKAWAY: Mr. Examiner, we will be happy to stipulate that that is one problem with the report.

PRESIDING EXAMINER: I think we have explained what that figure shows. Let's go on.

MR. NORRIS: All right, sir.

[4,043]

Testimony of Frank E. Baker

BY MR. NORRIS:

Q. Now, Mr. Baker, earlier you testified that you were unable to say today what the typical gas purchase contract provided for as a matter of take and that perhaps the twenty years that you had used in this report might be subject to change today.

Mr. Baker, are you aware that in the temporary certificates which the Federal Power Commission presently issues

[4,044]

a provision is generally included which limits the take-or-pay provisions of those contracts to 1-to7300 on a reserve basis?

A. No, sir, I was not.

Q. If such is the case, however, it would confirm the validity of using the 20-year depletion period, would it not?

A. Yes, sir.

Q. Now, let's turn to page 16 of Exhibit No. 9, and the last complete sentence appearing on that page which states that most of the new reserves are of the high-deliverability type which can produce volumes several times greater than contract rates.

First let me ask you, I believe you indicated earlier that the highest take provision that you had seen in a contract was some 200 percent deliverability swing. Is that correct?

A. That was the actual take from a particular source in the offshore Louisiana area, as I remember.

Q. Well, will most reserves produce more than ten percent of the ultimate recoverable volume in the first year?

A. Initially I don't know about most, but I am sure quite a few sources would be able to if they were fully

developed with enough wells and so forth to take advantage of their deliverability.

Q. Well, on a normal or reasonable pattern of development, would you expect the reserves to be able to produce more than ten percent a year of the ultimate recoverable reserves?

[4,045 & 4,046]

A. As I say, if the field was developed before it was dedicated, it is probable that the field could produce possibly ten percent of its reserves maybe the first year. I suppose there are exceptional cases where maybe the second, I don't know. But after that it would probably taper off rather rapidly.

Q. Then "several times," as it appears in this sentence, might be better stated as as much as two times its contract rate?

A. Yes, that would probably quantify it better.

Q. As a matter of fact, if a producer installed facilities at the well or a pipeline installed facilities to take the gas at this rate, then after one, or I believe you said at the most two years, there would be excess capacity in these facilities, would there not?

A. That is possible. Unless the field has grown beyond original exceptions or another field in the immediate vicinity had been dedicated.

Q. That would mean that the same producer probably would have to own those reserves in another field in order to utilize that equipment, would he not?

A. Possibly. But I don't think it is necessarily so.

Q. Now, just to be completely clear, Mr. Baker. The reserves additions which you have projected at the historical rates would contemplate the development of additional reserves within leases presently held and would not depend solely on new

offshore lease sales, would it?

A. No, sir, it would not. It includes everything: extensions, revisions, discoveries from new reservoirs and new fields, and leases which have not been let.

Q. You did not intend in the section of the report for which you are responsible to imply that the pricing policies of the Federal Power Commission have not had any effect on reserves additions, did you, Mr. Baker?

A. Excuse me. Could you read that back?

(Question read.)

THE WITNESS: I will answer it this way: In the part of the report I was responsible for I did not intend to imply that the pricing policies of the Federal Power Commission had anything to do with the reserve addition level, past or future.

MR. JONES: Could we have that answer read back, please?

(Answer read.)

BY MR. NORRIS:

Q. Let me get the converse of it. I believe that is the answer that Mr. Goldberg got. The question that I was posing to you was did you intend to imply that those pricing policies have not had an effect on reserves?

MR. HARKAWAY: Your Honor, I think he has answered the question.

[4,048]

MR. NORRIS: I don't believe I got an answer to my question.

PRESIDING EXAMINER: All right. Go ahead, answer it.

THE WITNESS: I'm sorry. I will have to have it read back again.

(Question read.)

THE WITNESS: I did not intend to imply that the pricing policies of the Federal Power Commission had any effect on reserve additions.

Is that the answer?

MR. HARKAWAY: It is not the answer he wants, but it is the answer he got.

Excuse me, your Honor.

BY MR. NORRIS:

Q. In other words, you are saying the pricing policy of the Federal Power Commission had nothing to do with your study, you didn't consider it one way or the other?

A. That's right.

Q. Mr. Goldberg was earlier asking you as to whether the level, or rate of exploration of independent producers is influenced by their projection of demand and whether they might expect a higher level of exploration with a higher projection of demand than with a lower projection of demand. I would ask you, would not profitability also influence the rate of exploration?

[4,049]

A. I would think that would be a very important aspect of it.

Q. And with respect to your showing some 40 percent of the projected demand to be met from Southern Louisiana, Mr. Baker, you show in each of the other producing areas a deficiency as well as for Southern Louisiana, do you not?

A. Yes. It is pro-rated, as I remember.

Q. Then if Southern Louisiana is unable to meet the 40-plus percent projection which you have made, then the projected deficiencies in other areas will be exacerbated, will they not?

A. Could you possibly define that?

Q. Worsened?

A. Yes, sir.

Q. It is my understanding that in determining whether a deficiency in fact exists the additions demand for each year is 20 times increased demand or new markets plus 20 times the expired contract volumes or approximate replacement. Is that correct?

A. Yes, sir. It is 20 times the increment—annual increment of production plus 20 times what it was—excuse me. It is 20 times the sum of the annual increments of production plus 20 times the sum of the incremental increases in production 20 years prior to this point in time, and also 40 years prior to that point in time.

[4,050]

Q. Mr. Baker, are you advocating that the Federal Power Commission only issue certification of new expansion of pipeline facilities on a showing of additional reserves sufficient to meet these demand qualifications?

A. No, sir.

Q. Turning to page 1104 of your prepared testimony and your definition of productive capability appearing on lines 13 and following, you state at line 16 that the estimate is made without specific regard to number of available wells.

Would you agree that there are limitations placed on deliverability at the present time by the number of wells which have been actually drilled in the formation?

A. Yes.

Q. And that limitations also exist through nonavailability of pipeline facilities or wellhead facilities?

A. Yes.

Q. I take it in light of your answer to my prior question concerning the ability of fields to produce at a maximum rate that you would not advocate the installation of facilities to take all of the gas which might be made available from a field today if in so doing the delivery capacity would of necessity be less than today's capacity tomorrow, i.e., uneconomic facilities?

A. No, I wouldn't advocate building facilities which were not economic.

Q. And facilities that would only be able to be used to

[4,051]

capacity for say one year's time would not, almost by definition, be economic, would they, Mr. Baker?

A. That's right.

Q. To the extent that these restrictions on capacity exist, then the critical R/P ratio would actually be reached earlier than you have projected in your study, would it not?

A. Well, the critical R/P—the definition of the critical R/P ratio depends on the historical growth rate for production for that particular area. If you had a constraint on the amount of pipeline capacity, number of wells and so forth, this would be a constraint on the growth of production and the production would not increase as fast as we have it projected.

Q. So the critical R/P ratio would actually be at some point higher than 9, though it can't be quantified at this time due to the inability to quantify these restraints—or higher than 8. I beg your pardon.

A. This critical R/P ratio is an optimum indicia type of number.

Q. Nonassociated and associated dissolved gas in your study are assumed to have the same productive capability, as indicated in lines 19 and 20 on page 1104.

In order to actually take advantage of the capability of associated gas at the same rate you would use the capability of nonassociated gas, it would be necessary that all of the oil production in Southern Louisiana be produced on a hundred percent

capability basis, would it not?

A. That's right.

Q. And even if this situation exists, then the 150 percent scheduled production which you refer to in lines 21 and 22, or swing, could not be taken on associated gas reserves; is that correct?

A. No, sir. That would be determined by the capability of the wells to produce. In Form 15, many times the associated solution reserves are scheduled right with the nonassociated and it is impossible to separate them out.

Q. Right. I was not questioning the study, but just the basis on which some of these assumptions are made.

A. Yes, sir.

Q. Now, what you have classified as uncommitted gas on page 21 of the report—

MR. GOLDBERG: What is your question?

MR. NORRIS: I say what he is classifying as uncommitted gas—and let me get him a better reference on that to give him. And that would appear on page 18 of the report in the second sentence.

BY MR. NORRIS:

Q. —actually is determined by the production experienced times 20, rather than the contractual situation with respect to Southern Louisiana gas reserves; is it not?

A. Yes, sir.

[4,053]

Q. And so to the extent that pipelines in the past have taken gas at less than 1 to 7300, or a 20-year depletion pattern, then to that extent uncommitted gas would be overstated, would it not? If the pipeline is taking only 4 percent of the reserves, say?

A. I don't believe I know the reference to uncommitted—excuse me. This study here on page 18 is related to the total U. S. We have not tried to relate that in any way to South Louisiana area.

Q. I beg your pardon. Then speaking in the context of the total U. S., if pipelines have taken gas at less than a rate of 5 percent a year on reserves dedicated to them, then to that extent the uncommitted portion could be overstated in your study; is that correct?

A. I believe that's correct, yes, sir.

Q. So that if, for instance, the Hugoton-Anadarko production is being taken at a rate of 2 percent per year or 3 percent per year, then it would result in a substantial overstatement in the uncommitted portion, would it not?

A. That's correct.

Q. In the uncommitted category again, I think you would also include gas presently being used in cycling projects, would you not?

A. That's correct.

Q. And to that extent, then, the uncommitted portion

would also be overstated, would it not?

A. Yes, sir.

Q. Do you know the magnitude of the volumes of gas which are presently being cycled?

A. No, sir, I don't.

Q. Do you have a copy of a report entitled "Gas Supplies of Interstate Natural Gas Pipeline Companies for 1968," published by the FPC in January of 1970, available?

A. Yes, sir.

Q. Would you turn to page 54 of Appendix C of that report, please. Actually, that reference should be page 53, Mr. Baker.

A. Yes, sir, I have it.

Q. Would you accept, subject to check, that for the year 1968 Colorado Interstate Gas Company shows a downward revision of 17.7 percent in their reserves committed? That would be in the column 1968, under "Increase or Decrease," or just beyond it.

A. You are speaking of the figure 241,468?

Q. Right.

A. Yes, sir.

Q. And that a similar figure for Florida Gas Transmission indicates an 11.7 percent downward revision?

A. Yes, sir.

Q. That the Montana-Dakota Utilities Company, a downward revision of 13.7 percent is shown?

[4,055]

A. Yes, sir.

Q. That South Texas Natural Gas Gathering Company, a downward revision of 13.6 percent is shown? That is on page 54.

A. Yes, sir.

Q. That for Texas Gas Transmission a downward revision of 8.7 percent is shown?

A. Yes, sir.

Q. And for United Fuel Gas Company a downward revision of 8.6 percent is shown?

A. Yes, sir.

Q. And for United Gas Pipeline Company a downward revision of 9.8 percent is shown?

A. Yes, sir.

Q. Now, I believe you previously testified that the Staff does audit or analyze these Form 15 reports?

A. Yes, sir.

Q. Do you consider these to be substantial revisions?

A. They appear to be on the face value of the report.

Q. Wouldn't these downward revisions then tend to confirm the downward revisions in the AGA data for the same year?

A. They appear that they certainly would have some corollary effect there.

* * * *

[4,059]

PROCEEDINGS

PRESIDING EXAMINER: All right, Mr. Norris, you may proceed.

FRANK E. BAKER

the witness on the stand at the time of recess, resumed the stand, and upon examination, testified further as follows:

* * * *

[4,074]

• • • •

BY MR. HARKAWAY:

Q. Mr. Baker, in response to a question by Mr. Norris yesterday I believe you indicated that the Form 15 trends tended to confirm the AGA report of a downward trend in gas reserves.

A. Yes, sir.

Q. In fact, the Form 15 report does not show gas in the intrastate market, does it?

A. Some of the reports do include a portion of that.

Q. What reports would those be?

A. United Gas Pipeline is the one that comes to mind.

Q. By and large, most other reports do not include intrastate dedications or intrastate sales; is that right?

A. That's right.

Q. The Form 15 report does not include gas which is not under contract to pipelines; is that correct?

A. That's correct.

Q. The Form 15 report does not include gas which is under contract but not certificated. Is that correct?

A. That's correct.

Q. The Form 15 does not include gas which is used by producers themselves in their plants or otherwise, is that correct?

A. That's correct.

[4,075]

Q. The Form 15, in fact, does not include many of the sources which are included in the AGA report?

A. That's right.

Q. The Form 15 is not prepared on a same or com-

parable basis to the AGA report preparation; is that correct?

A. I really don't know.

Q. In your opinion, is it appropriate to compare the Form 15 to the AGA report?

MR. NORRIS: In what respect, counsel?

BY MR. HARKAWAY:

Q. For purposes of determining any trends as to gas supplies?

A. Yes, sir, I think it is appropriate. The trends for the Form 15 data from '63 through '69 for reserves-production, R/P ratio, very closely parallel the trends for the AGA data for the same period of time. The Form 15 reserves are equal to approximately 71 percent of the AGA reserves, and the Form 15 production is equivalent to about 66 percent of the AGA production.

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[4,076]

answered, your Honor.

Just a moment or two ago the counsel took him through what was included in Form 15 and whether that was or was not included in AGA reserves, and this is really arguing with the witness.

MR. HARKAWAY: I don't think Mr. Norris has heard the question, your Honor.

MR. NORRIS: I heard it twice, counsel.

MR. HARKAWAY: Because it certainly was not.

PRESIDING EXAMINER: Do you know the answer to the question?

THE WITNESS: Yes. As I understood the question, do reserves have to be dedicated to interstate pipelines to be included in the AGA reserves estimates. And the answer to this is no.

BY MR. HARKAWAY:

Q Let me reframe the question then, Mr. Baker.

Is there a direct correlation between the data in the Form 15 and the AGA reports?

A. Not a direct correlation. I really don't know exactly how to draw the comparison, but the reserve estimates are certainly associated with each other, because they come from the same fields in many instances.

Q. If next year's Form 15 reports when tabulated by the staff indicated an increase in reserves dedicated to pipelines, would it be proper to assume that therefore there has been an

increase in reserves—proved reserves under the AGA report?

A. Not necessarily. Some of these increases in the form 15 data could have been under contract but not certificated by the pipeline companies, and—well, that is the primary one.

Q. So in fact you cannot trend one in accordance with the other; is that correct?

A. Not perfectly, but over a period of years in gross amounts you could.

Q. In response to questions by Mr. Norris, I believe you indicated yesterday that the take-or-pay provisions calling for a one for 7,300 Mcf take confirms the validity of the use of the twenty-year period for gas contracts. Do you recall that question and answer?

A. Yes, sir. For the South Louisiana Area.

Q. Yes.

In fact, a take-or-pay provision does not limit the amount of gas that a pipeline can take from the producer; is that correct?

A. That's correct.

Q. A take-or-pay provision requires that a pipeline take a minimum amount or pay for it; is that right?

A. Yes, sir.

Q. So that a take-or-pay provision calling for one for 7,300 take does not have any relationship to the length of life

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